

**INTEGRATED SIMULATION AND EFFICIENCY ANALYSIS
OF ASP FLOODING USING CMG-STARS FOR ENHANCED
OIL RECOVERY IN THE KASHAGAN OIL FIELD**

by

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ORIGINALITY STATEMENT

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ABSTRACT

Alkali-Surfactant-Polymer (ASP) flooding for enhanced oil recovery (EOR) at the Kashagan oil field, one of Kazakhstan's most technically difficult reservoirs, is thoroughly evaluated using simulation in this thesis. Conventional recovery techniques are still mostly ineffectual in the presence of high hydrogen sulfide gas concentration, high formation water salinity (>180,000 ppm), and high reservoir temperatures (~99°C). However, by lowering interfacial tension, increasing mobility ratio, and changing wettability, ASP flooding has the potential to get beyond these restrictions. The study simulates ASP flooding performance under different salinity levels, chemical concentrations, and well placement patterns using the CMG-STARs simulator. It was chosen to apply cartesian grid system with dimensions of 15*15*7 blocks for heterogeneous, anisotropic reservoir model. Rock properties were used as general values for carbonate reservoirs, while fluid properties were used for Kashagan oil sample. Initial conditions for pressure, temperature, and saturation are based on average reservoir characteristics from the literature review. The main well placement scenario was chosen to be normal 5-spot pattern, while the sensitivity analysis also considers middle 5-spot, normal 7-spot, and middle 7-spot well placements. Alkali-surfactant (AS), polymer-only, and complete ASP flooding strategies were all compared in simulations based on the cumulative oil production results. The findings showed that ASP flooding outperformed AS and polymer flooding alone, with the largest cumulative oil recovery (~360,000 bbl) and the lowest water-oil ratio (~11). Additional sensitivity analysis showed that optimal well designs (normal 5-spot pattern) and reduced injection salinity greatly improve oil recovery. The best chemical composition, consisting of 0.4 weight percent alkali, 0.1 weight percent surfactant, and 0.075 weight percent polymer, has the maximum economic return with a pseudo-NPV of \$27.2 million, according to the thesis, which also includes pseudo-economic analysis. For high-salinity, carbonate reservoirs like Kashagan, the results indicate that ASP flooding is both technically feasible and economically beneficial with the right optimization, despite operational obstacles such chemical degradation and adsorption.

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1. INTRODUCTION

1.1 Introduction

The oil and gas sector are under growing pressure to create effective, economical techniques for recovering the residual hydrocarbons from traditional oil reservoirs as they continue to mature globally. This problem is especially noticeable in places like Kazakhstan, where a lot of big oil fields, like the Kashagan field, have low-permeability zones, complicated carbonate formations, and high salinity, all of which make it very difficult to use traditional recovery methods (Brunet et al., 1999; Isabaev & Boiko, 2015). The implementation of tertiary recovery techniques, commonly referred to as enhanced oil recovery (EOR), is necessary in these situations as primary and secondary recovery techniques frequently leave more than 50% of the original oil in place (OOIP) (Sheng, 2010).

Chemical approaches, particularly Alkali-Surfactant-Polymer (ASP) flooding, have demonstrated significant promise in enhancing oil recovery efficiency among the several EOR procedures (Chang et al., 2006; Sheng, 2011). The advantages of three chemical agents are combined in ASP flooding: polymers, which increase the mobility ratio and improve sweep efficiency; surfactants, which lower interfacial tension between oil and water; and alkali, which reacts with acidic components in crude oil to produce in-situ surfactants and change rock wettability (Green & Willhite, 1998; Sorbie, 1991). ASP is a potent technique for releasing residual oil in mature and difficult reservoirs because these compounds, when properly prepared and injected, may greatly boost microscopic and macroscopic displacement efficiency.

The Kashagan field in Kazakhstan offers EOR a technically challenging setting. The use of chemical flooding necessitates careful modeling and optimization to guarantee technical feasibility and economic viability due to fractured carbonate deposits, salt levels above 180,000 ppm, and reservoir temperatures nearing 99°C (Akhmedzhanov et al., 2012; Huang et al., 2017). Although surfactant and polymer flooding have been tried separately in several of international projects, ASP flooding is still not widely used in Kazakhstan because of the absence of customized modeling data and perceived operational difficulties (Firozjahi & Moradi, 2018; Shurong et al., 2018).

Chemical approaches, particularly Alkali-Surfactant-Polymer (ASP) flooding, have demonstrated significant promise in enhancing oil recovery efficiency among the several EOR

procedures. The advantages of three chemical agents are combined in ASP flooding: polymers, which increase the mobility ratio and improve sweep efficiency; surfactants, which lower the interfacial tension between oil and water; and alkali, which reacts with the acidic components in crude oil to produce in-situ surfactants and change rock wettability. ASP is a potent technique for releasing residual oil in mature and difficult reservoirs because these compounds, when properly prepared and injected, may greatly boost microscopic and macroscopic displacement efficiency.

EOR operates in a technically challenging environment in Kazakhstan's Kashagan field, one of the biggest offshore oil finds in recent decades. The use of chemical flooding necessitates careful modeling and optimization to guarantee both technical and financial feasibility because to the reservoir's near-99°C temperatures, salt levels above 180,000 parts per million, and cracked carbonate deposits. Although surfactant and polymer flooding have been independently evaluated in a number of international projects, ASP flooding is still not widely used in Kazakhstan because of the lack of customized modeling data and perceived operational difficulties.

The purpose of this thesis is to use the CMG-STARs (Computer Modelling Group – Steam, Thermal, and Advanced Processes Reservoir Simulator) platform to assess and optimize ASP flooding for a reservoir modeled after the Kashagan field. Through numerical modeling, the study compares the flooding processes of polymers, alkali-surfactants (AS), and ASP in detail, concentrating on their combined oil production, water cut behavior, and economic effect. The impacts of different chemical concentrations, injection techniques, and well placement patterns are also examined in this study. The best formulations are found using sensitivity analysis, and the most economical strategy is found using pseudo-economic assessment.

This study is important because it might help direct future field-scale ASP applications in Kazakhstan and other high-salinity, low-permeability reservoirs of a similar kind. This research offers a technological and financial foundation for developing chemical EOR strategies in the area by utilizing simulation tools such as CMG-STARs and carrying out comprehensive performance and sensitivity analyses.

1.2 Background of Study

The world's oil production has been moving more in recent decades toward older and complicated reservoirs, where conventional recovery techniques are no longer adequate to

sustain profitable oil supply. Only 20–40% of the OOIP is normally extracted by primary and secondary recovery techniques, leaving a sizable number of hydrocarbons trapped because of heterogeneity, low permeability, or unfavorable rock-fluid interactions (Green & Willhite, 1998). This problem is especially important in Kazakhstan, where the main oil fields, such as Kashagan, Karachaganak, and Tengiz, have enormous amounts of leftover oil but present significant technical difficulties because of their high salinity formation waters, carbonate lithologies, and fluctuating pressure-temperature regimes (Isabaev & Boiko, 2015; Brunet et al., 1999).

For example, the temperature in the Kashagan area is close to 99°C, the salinity is above 180,000 ppm, and the matrix permeability is low (~3 mD). These factors restrict the efficacy of waterflooding and make traditional chemical EOR methods more difficult (Akhmedzhanov et al., 2012; Sheng, 2011). Problems including scaling brought on by alkali reactions, surfactant adsorption, and polymer degradation reduce chemical efficiency and raise operating expenses (Hirasaki et al., 2008; Levitt et al., 2009). Additionally, early water breakthrough and low sweep efficiency might result from carbonate reservoirs' fractured character, which further lowers recovery potential (Hirasaki & Zhang, 2004; Rao, 1999).

By reducing interfacial tension, increasing mobility ratio, and changing wettability, ASP flooding is a viable remedy despite these problems (Bataweel & Nasr-El-Din, 2012). However, meticulous optimization of well patterns, injection rates, slug design, and chemical formulation is necessary for successful deployment (Feng et al., 2013). To assess performance under actual circumstances, these parameters—which are extremely reservoir-specific—need to be accurately numerically simulated using programs like CMG-STAR3 (Huang et al., 2017; Firozjahi & Moradi, 2018).

There is currently a dearth of comprehensive field-based ASP data and modeling techniques in Kazakhstan. With little understanding of integrated ASP processes and their economic effects, existing research is on solo polymer or surfactant flooding (Shurong et al., 2018; Sarapardeh et al., 2013). This knowledge gap prevents ASP flooding from being widely used in Kazakhstan's carbonate reservoirs and limits data-driven decision-making.

For instance, the Kashagan field's formation water salinity exceeds 180,000 parts per million, its temperature is close to 99°C, and its matrix permeability is quite low (~3 mD). These factors restrict the efficacy of waterflooding and make the use of traditional chemical EOR procedures

more difficult. Under these circumstances, scaling from alkali reactions, surfactant adsorption, and polymer degradation become major issues that lower chemical efficiency and raise operating expenses. Recovery may also be further limited by early water breakthrough and low sweep effectiveness caused by the fragmented character of carbonate reservoirs.

Chemical EOR techniques, particularly ASP flooding, provide a viable way forward in spite of these obstacles. By reducing interfacial tension, increasing mobility ratio, and changing wettability, ASP flooding aims to alleviate both microscopic and macroscopic displacement inefficiencies. But for it to be implemented successfully, well patterns, injection rates, slug design, and chemical composition must all be carefully optimized. To assess these parameters' performance under realistic subsurface circumstances, precise numerical modeling is necessary since they are extremely reservoir-specific.

As of right now, Kazakhstan lacks simulation-supported approaches and a wealth of field data to implement ASP flooding in its challenging reservoir conditions. Without addressing the intricate relationships and financial ramifications of integrated ASP processes, the majority of existing research is on single polymer or surfactant flooding. Operators and engineers are unable to make well-informed judgments on the viability and potential of chemical EOR in Kazakhstan's carbonate fields because of this gap.

To assess and improve ASP flooding performance under regional geological and operational circumstances, simulation-based research is obviously required. The foundation for well-informed field application and investment planning is a well-calibrated simulation model that may offer insights into the potential for oil recovery, the behavior of water production, and economic implications.

1.3 Problem Statement

The Kashagan field and other large oil fields in Kazakhstan are experiencing a decline in output because of the constraints of primary and secondary recovery techniques. Even if there are sizable reserves left, traditional methods like waterflooding are far less effective in reservoirs with high salinity, high temperatures, and limited permeability. Although chemical enhanced oil recovery (EOR) techniques, especially Alkali-Surfactant-Polymer (ASP) flooding, have demonstrated significant potential in enhancing recovery under comparable circumstances in other places, their use in Kazakhstan is still restricted because there is a dearth of comprehensive,

field-specific simulation data and optimization studies. A better knowledge of how ASP systems react in local subsurface circumstances is necessary due to the complexity of carbonate reserves and operational hazards including chemical loss and polymer degradation.

Research on the numerical modeling and optimization of ASP flooding specifically for high-salinity reservoirs like Kashagan is still lacking. Operators are unable to make data-driven choices about the large-scale implementation of ASP if chemical interactions, slug design, injection tactics, and economic viability are not properly evaluated. The development of tertiary recovery technologies in Kazakhstan is hampered by this lack of localized, simulation-based understanding. In order to evaluate the technical performance and economic feasibility of ASP flooding and facilitate better oil recovery and field development planning in the area, a methodical simulation study is required.

1.4 Objectives of the Thesis

The purpose of this research work is to analyze efficiency of ASP flooding in Kashagan oil field to improve oil production. The aims of the study are the following:

- To Simulate and analyze ASP flooding performance in the Kashagan oil field using the CMG-STARs reservoir simulation software.
- To Evaluate the sensitivity of ASP efficiency to key operational parameters, including well placement patterns, salinity levels of the injected fluids, and chemical concentrations.
- To Conduct an economic assessment of various ASP flooding scenarios to determine the most cost-effective recovery strategy.

2. LITERATURE REVIEW

2.1 Overview

To maximize hydrocarbon extraction after the primary and secondary recovery phases, enhanced oil recovery, or EOR, is essential. Chemical flooding, particularly Alkaline-Surfactant-Polymer (ASP) flooding, has become one of the most promising EOR approaches for increasing oil displacement and sweep efficiency in heterogeneous reservoirs. The principles of ASP flooding, the function description of each ASP slug member (polymer,

surfactant, and alkaline), the primary procedures involved in chemical application, modeling techniques utilizing CMG-STARs, and its field-level efficiency are all covered in detail in this chapter's extensive literature review. It ends with a synopsis and a list of research gaps that support the current investigation.

2.2 Kashagan Oil Field

In the southern flung of the Astrakhan-Aktyubinsk elevation system of the basal complex, Kashagan field is in the southern portion of the Pre-Caspian depression and is connected to the Tengiz-Kashagan interbasin carbonate platform (Fig. 1). The shared Devonian (late Frasnian-Famennian) carbonate foundation supports distinct early Carboniferous carbonate blocks that make up the platform. Karaton, Tengiz, and Korolev lie on the eastern Caspian shore, whereas Kashagan, Kashagan South-West, Aktote, and Kairan are on the Caspian shelf. In Kashagan, deposits from the Devonian to the Elephantine were penetrated. In KE-1, the longest part that could be drilled through was 5172 meters. The drill record showed that the Lower Permian salt-bearing portion had thick Kungurian separating the pre-salt and post-salt layers. The Kashagan field is in the southern portion of the Pre-Caspian depression in the southern flung of the Astrakhan-Aktyubinsk elevation system of the basal complex, and it is connected to the Tengiz-Kashagan interbasin carbonate platform. The pre-Caspian basin was formed between Paleozoic and Cenozoic times (Brunet et al., 1999).



Figure 1. Kashagan oil field geographical placement (Ybray, et al., 2011)

2.3 EOR Projects and Challenges

A popular method of producing oil that reduces the scarcity of crude oil resources and their high cost is enhanced oil recovery, or EOR. This method recovers a significant amount of crude that is left in wells after the natural extraction process. A significant portion of original oil in place (OOIP), often exceeding 70%, remains unextracted because of the natural extraction process (primary recovery), which uses the reservoir's inherent pressure to extract crude oil. EOR, often referred to as tertiary recovery, and secondary oil recovery, which uses fluid (mostly gas and water) injection to increase reservoir pressure, are hence essential for enhancing oil recovery. EOR approaches entail altering the composition of the reservoir, whereas secondary recovery uses gas or water injections to assist move the oil through the wells without altering the hydrocarbon's true characteristics. Essentially, significant characteristics of the crude oil, such as its density and viscosity, alter, which facilitates oil displacement in the reservoir (Sarapardeh et al., 2013; Sarapardeh et al., 2015).

A variety of enhanced oil recovery (EOR) techniques, such as thermal approaches, alkaline/surfactant/polymer (ASP) flooding, polymer flooding (PF), and miscible CO₂ flooding, are employed to recover residual oil by altering fluid/rock interactions in a specific oil-water-rock

system. Each technique has uses depending on the qualities of the oil, the reservoir, and the viability of the business. Reservoir heterogeneity, chemical adsorption and retention, high operating costs, scalability problems, or chemical degradation are some of the obstacles that EOR techniques must overcome. This section discusses a few issues related to polymer, alkaline, and surfactant flooding. Chemical EOR can be technically possible, but it requires careful planning and modeling to be economical and scalable, as demonstrated by previous field operations like the Daqing Field in China and the Marmul Field in Oman. Brine salinity and hardness have a negative impact on critical polymer qualities such as viscosity and adsorption, which decreases their efficacy (Sheng, 2010; Shakeel et al., 2020). The high formation temperature, which leads to significant thermal deterioration of HPAM, is another restriction on the use of polymer flooding in carbonates. (Guan and Du, 2004)

2.3.1 Challenges of Alkaline Application in Oil Fields

The efficacy of alkaline flooding in the field may be limited by several operational and technical issues, notwithstanding its potential advantages. The injected alkaline solution (usually sodium hydroxide, sodium carbonate, or sodium orthosilicate) reacts with the divalent cations (calcium and magnesium) in the formation water to cause scaling and precipitation, which is one of the main problems. Injectivity is hampered because of formation damage and decreased permeability (Sheng, 2011; Hirasaki et al., 2008). The necessary alkaline dose and operating costs are further increased by chemical consumption through side reactions, especially with silicate minerals and acidic crude oil components (Tang et al., 1991). Furthermore, alkali/oil systems frequently exhibit emulsion formation, which makes surface oil-water separation procedures more difficult (Hirasaki & Zhang, 2004). Particularly in high-salinity situations where precipitation of insoluble salts (such as calcium carbonate or magnesium hydroxide) is possible, the effectiveness of alkaline flooding is extremely sensitive to the formation mineralogy and brine composition (Krumrine & Falcone, 1983; Lake, 1989). Furthermore, if appropriate corrosion inhibitors are not applied, high pH fluids used in alkaline flooding may provide corrosion threats to surface facilities and downhole tubing (Sheng, 2011). To guarantee the viability of alkaline flooding in a particular reservoir, these difficulties call for stringent laboratory screening, water softening, and compatibility testing.

2.3.2 Challenges of Surfactant Application in Oil Fields

Because it may drastically lower IFT and release leftover oil that has been confined by capillary forces, surfactant flooding is a potent EOR technique. However, several technological and financial obstacles stand in the way of its effective field deployment. Adsorption of surfactants onto reservoir rock surfaces, especially in sandstones and carbonates, is one of the main problems. This can result in significant surfactant loss and higher project costs (Rao, 1999; Sheng, 2011). In rocks with a high cation-exchange capacity or a high clay concentration, this impact is more pronounced. Furthermore, rock mineralogy, temperature, pH, and reservoir salinity all have a significant impact on surfactant retention (Austad et al., 1998). Chemical stability in challenging reservoir conditions is another significant obstacle. At high temperatures ($>90^{\circ}\text{C}$), high salinities ($>100,000$ ppm TDS), or in the presence of divalent cations such as Ca^{2+} and Mg^{2+} , which can cause precipitation or phase separation, many surfactants deteriorate or lose their efficiency (Hirasaki et al., 2011; Nelson & Pope, 1978). It takes a lot of laboratory experimentation to create surfactant formulations that are stable and effective in these kinds of environments, which lengthens the time and expense of development. Moreover, emulsion development in the reservoir and surface facilities due to surfactant flooding may complicate oil-water separation and raise the possibility of production disruptions (Green & Willhite, 1998). If surfactant compatibility with brine and formation fluids is not adequately handled, operational issues including foaming, injectivity decrease, and scaling in surface lines may also arise. To overcome these obstacles and maximize the usage of surfactants in field applications, customized chemical design, sophisticated screening procedures, and reliable modeling tools are required.

2.3.3 Challenges of Polymer Application in Oil Fields

By making the injected fluid more viscous, polymer flooding is frequently used in enhanced oil recovery (EOR) to increase the mobility ratio between displaced oil and displacing water. The first thickening agent for aqueous solutions was polyacrylamide, or PAM, which had a molecular weight greater than 1.0×10^6 g/mol. PAM stays constant at the sea's normal salinity of 90°C and higher, up to 62° . It is therefore restricted to on-shore activities only. The viscosity properties of the PAM may be diminished by high salinity. Partially hydrolyzed polyacrylamide (HPAM) is one of the most used polymers in use today. Acrylamide and sodium acrylate can copolymerize to create HPAM, or PAM can be partially hydrolyzed. The advantages of HPAM include its affordability, ability to withstand high mechanical loads that arise during reservoir flooding, and

resistance to bacterial assault. Depending on how harsh the brine is, this polymer may achieve temperatures of up to 99°C (Olajire, 2014). Some of its variations, as HPAMAMPS co-polymers and sulphonated polyacrylamide, can withstand temperatures of 104°C and 120°C, respectively (Abidin et al., 2012). The disadvantage of HPAM is its high sensitivity to brine salinity, hardness, and the addition of surfactants or other substances. It is therefore completely ineffective in reservoirs that include salt.

Zeito developed a 3-dimensional, 2-phase, incompressible finite-differences simulator (Zeito, 1968). Polymer propagation is studied by mass transfer alone; this simulator is unable to represent dispersion, capillary, or gravitational forces. The solution's viscosity is influenced by the concentration of the polymer.

Jewett and Schurz developed a two-dimensional, five-spot, two-phase finite differences simulator (Jewett & Schurz, 1970). There is no information interaction between the levels. They ignored capillary and gravitational forces in their model. Adsorption is modeled using Langmuir type adsorption.

Eljareh et al. (2024) used the CMG reservoir simulator to assess the impact of polymer flooding on oil recovery. UmmFaroud Field is the target of the simulation. The study's findings on the impact of polymer concentration on cumulative oil output, water cut, and oil rate are shown as follows:

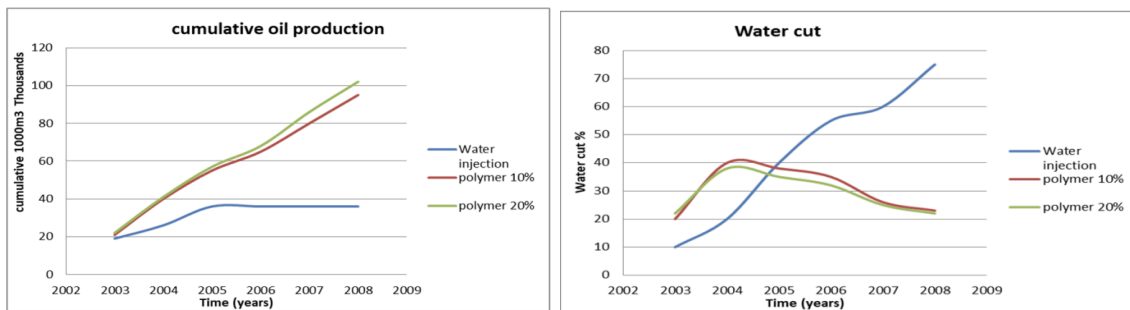


Figure 2. a) Cumulative oil production and b) Water cut in Umm Faroud Field (Eljareh et al., 2024)

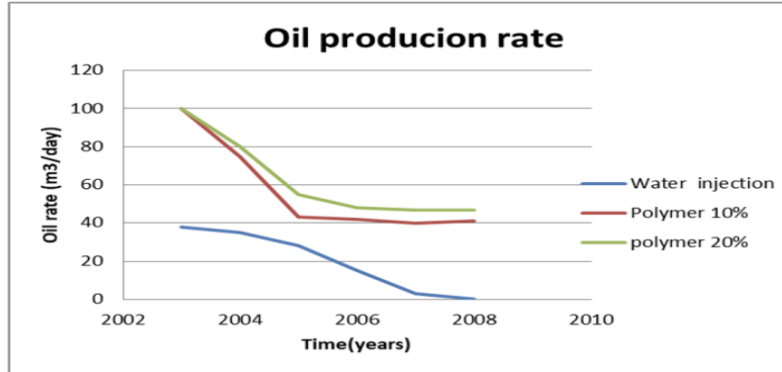


Figure 3. Oil production rate in Umm Faroud Filed at different polymer concentrations (Eljareh et al., 2024)

A compressible, three-phase, four-component, finite difference simulator was created by Bonder, Hirasaki, and Tham. According to Bordor et al. (1972), the polymer solution is represented as the fourth element in the aqueous phase. Adsorption is computed in relation to polymer content, pore volume, adsorptive capacity, and the grid block's percentage of the mobile aqueous phase. A residual resistance factor is used to model mobility decline.

A water/polymer flooding prediction system was developed by Jones et al. (Jones et al, 1984). Validation of this semi-analytical prediction model has been conducted using analytical computations, field data, and simulators. It produces faster results and is not a numerical simulator. A dissolved substance in the aqueous phase is called a polymer. The volume of inaccessible pores is user-defined. The polymer solution has Newtonian viscosity.

One of the major polymer challenges is fingering problem. The extent of this problem can be access by mobility ration value. The mobility ration is an important parameter to consider in any flood operations. The formula is provided as follows:

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} \quad \text{Equation 1}$$

Mobility ration is preferred to be <1, at this condition water phase has less mobility than oil, therefore sweep efficiency is greater. When $M > 1$ the water fingering process may happen. This process is illustrated in figure 4.



Figure 4. Water fingering illustration (Jones et al., 1984)

At the upper part of the figure, oil phase is closer to the end of the layer, so water breakthrough will happen faster. The opposite situation is using the polymer solution which will reduce the mobility of water phase. Operational data indicate decreased residual oil saturation in certain circumstances and faster oil production overall.

Another one is polymer degradation due to shear, temperature, salinity, and biological activity. High shear rates during injection, especially through tight formations or narrow wellbores, can lead to mechanical degradation of polymers such as partially hydrolyzed polyacrylamide (HPAM), resulting in loss of viscosity and reduced sweep efficiency (Levitt et al., 2009; Sheng, 2011).

Degradation process is another concern which include biodegradation and thermal degradation. Biodegradation happened under the effect of bacteria which bound with polymers, that's leads to the break of intramolecular bonds in polymers. Thermal degradation has the similar mechanism; however, heat is the source of polymer breakage. The rate of polymer thermal degradation is shown in equation 2:

$$r_p = A * \exp \exp \left(-\frac{E_a}{R * T_{abs}} \right) \quad \text{Equation 2}$$

Where, A is Arrhenius constant, Ea is activation energy, R is universal gas constant, and Tabs is absolute temperature.

Mechanical entrapment is faced in the small pores, where the radius of polymer is larger, than radius of pores, therefore polymer is trapped in the porous media. Precipitation refers to the separation of polymer from aqueous solution into the solid phase on the rock surface. The lase mechanism is adsorption, which has highest importance for consideration. Adsorption process is a function of the polymer concentration, the relationship is described in figure 5 (CMG, 2019).

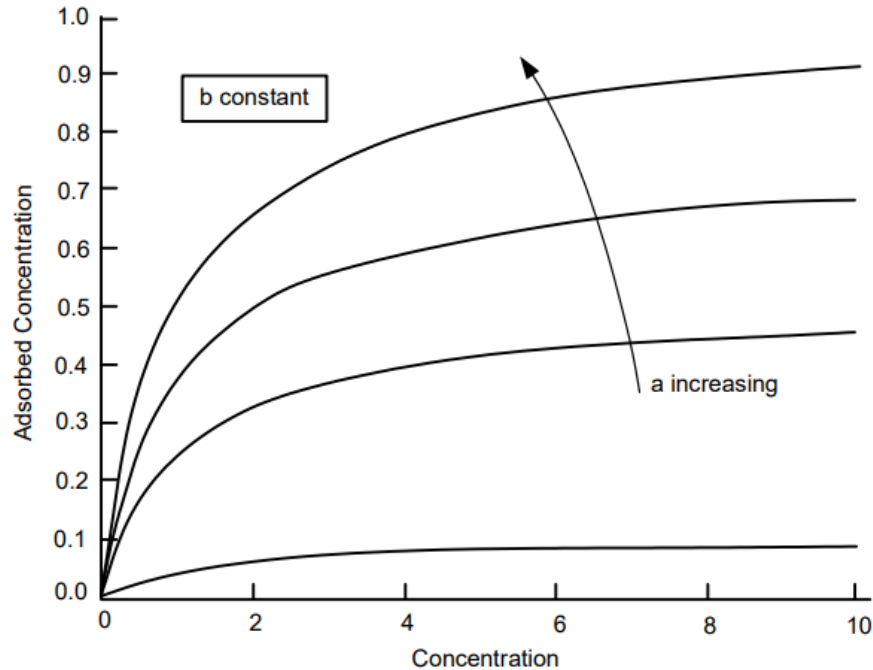
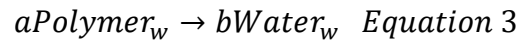


Figure 5. The dependence of adsorption from polymer concentration (CMG, 2019)

As the polymer concentration increases the adsorption increases. The function also dependent from the a and b coefficients. These coefficients are the stoichiometric coefficients of chemical reaction, that is described by equation 3:



Moreover, polymer adsorption and retention on reservoir rock surfaces can lead to significant loss of active polymer and reduce the effective mobility control. This is especially problematic in heterogeneous or clay-rich formations, where adsorption is higher (Sorbie, 1991). Injectivity reduction is also a major operational concern, as the increased viscosity of polymer solutions can lead to plugging or increased pressure drop near the wellbore (Pope et al., 2010). Finally, microbial activity in the reservoir can degrade polymer chains, form insoluble biomass and reducing performance unless biocides are used.

To address these issues, extensive laboratory testing, reservoir-specific polymer selection, and numerical simulation are required to ensure long-term performance and economic viability of polymer flooding projects.

The implementation of polymer flooding requires certain conditions. There are different papers describing the screening criteria for certain reservoir properties in different intervals, one of the screening tables containing polymer flooding is seen in table 1 (Adasani & Bai, 2011).

Table 1. Screening criteria for EOR methods (Adasani & Bai, 2011)

EOR method	No. projects	Reservoir properties						
		API	Viscosity (cP)	Start oil saturation	Permeability (mD)	Porosity (%)	Depth (ft)	Temperature (°F)
Miscible flooding	226	34-44	0-1	0.33-0.55	0.1-100	7-16	4200-6700	95-160
		73%	64%	62%	64%	62%	55%	52%
Immiscible flooding	40	19-36	0-10.5	0.42-0.62	30-300	22-32	1970-5708	120-194
		66%	58%	67%	53%	69%	51%	68%
Steam flooding	274	10-16	3-2000	0.50-0.70	1000-3000	30-38.8	800-1800	80-130
		78%	51%	64%	56%	76%	64%	77%
Combustion	27	19-27	1.44-2	0.50-0.70	10-85	17-25	1575-5000	185-230
		50%	67%	70%	52%	55%	48%	64%
Chemical (mainly polymer)	70	32-42.5	9-75	0.65-0.82	173-875	21-33	2723-3921	108-158
		52%	69%	65%	60%	67%	48%	65%

Note: Percentages represents project distributions.

With a molecular weight of more than 1.0×10^6 g/mol, polyacrylamide, or PAM, was the first thickening agent for aqueous solutions. PAM remains stable at typical salinity of 90°C at and above up to 62° salinity of the sea. As a result, it is limited to on-shore operations exclusively. High salinity can lessen the PAM's viscosity characteristics. One of the most widely utilized polymers in use today is partially hydrolyzed polyacrylamide (HPAM). HPAM can be produced via the copolymerization of acrylamide and sodium acrylate or by partial hydrolysis of PAM. The benefits of HPAM include its low cost, resistance to bacterial attack, and tolerance to strong mechanical stresses that occur during reservoir flooding. Temperatures up to 99°C can be reached with this polymer, depending on how hard the brine is (Olajire, 2014). Certain of its modifications, such sulphonated polyacrylamide and HPAMAMPS co-polymers, can tolerate temperatures of 120°C and 104°C, respectively (Abidin et al., 2012). High sensitivity to brine salinity, hardness, and the addition of surfactants or other compounds is HPAM's drawback. Because of this, it is incredibly useless in salt-containing reservoirs.

2.4 Hybrid ASP Flooding (Theory and Field Experience)

Alkali-Surfactant-Polymer (ASP) flooding is one of the most promising Chemical Enhanced Oil Recovery (EOR) techniques. It was suggested based on polymer flooding. ASP flooding aims to

increase sweep efficiency and displacement efficiency by simultaneously introducing polymer, surfactant, and alkali. Enhancing the mobility ratio by polymer usage significantly increases sweep efficiency. In order to increase the oil displacement efficiency, the alkali and surfactant are used to lower the interfacial tension between the displacing phase and the oil phase. Additionally, alkali may lessen the adsorption of pricey surfactants. Several outdoor testing as well as several laboratory studies have been conducted. According to the literature, there were three field tests—three in Canada, seven in the United States, and nineteen in China. According to recent statistics, 4495 wells were the subject of 14 field experiments and industrial applications between 2013 and 2015. With recovery percentages of up to 98% OOIP in lab tests, combined alkali-surfactant-polymer (ASP) flooding has been shown to be the most successful chemical EOR procedure (Fortenberry, 2013). Bataweel et al. conducted a comparison of alkali, surfactant, and polymer combinations in high salinity, high temperature Berea sandstone samples (Bataweel and Nasr-El-Din, 2012). The findings indicated that the ASP formulation with an anionic surfactant had a higher recovery factor than other combinations. Approximately 9% more oil was recovered by ASP flooding than by surfactant/polymer (SP) flooding. Because of the combined effects of the alkali and surfactant, as well as a polymer's reduction in displacing fluid mobility, the additional oil in ASP is recovered by a drop in IFT. The reduced adsorption of the polymer and surfactant in the presence of the alkali results in a cost-benefit analysis that requires fewer chemicals (Chang et al., 2006; Feng et al., 2013). Due to their geological complexity and challenging reservoir conditions, carbonates have virtually no large-scale application of ASP flooding, despite the promising outcomes of numerous lab-based studies. The pilot and field implementation of ASP flooding is primarily restricted to sandstone reservoirs (Dang et al., 2018).

Whereas mobility control influences sweep efficiency, capillary number determines displacement efficiency. It should be recognized that the definition of capillary number includes a viscosity component, meaning that capillary number can have an impact on both displacement efficiency and sweep efficiency. The polymer has minimal influence on residual oil saturation since it cannot considerably alter capillary number. Even while polymers can lower residual oil saturation in core flooding experiments, this is because heterogeneity always exists and increases sweep efficiency.

2.5 Previous ASP flooding modeling using CMG software

Using permeability, porosity, and saturation data, the geological model was successfully constructed in CMG-STAR5 and verified by comparing the production and injection data's histories. With cumulative production errors of less than 2%, the simulation demonstrated excellent agreement with actual field data, demonstrating the model's dependability for surfactant optimization research. According to simulations, oil recovery was typically enhanced by raising the surfactant content in the main slug from 0.1% to 0.4%. At larger doses, however, the recovery's marginal gain shrank. In order to balance enhanced recovery with economic viability, the ideal surfactant concentration for the primary slug was determined to be 0.3%. Increases over this threshold led to declining returns and perhaps problems with emulsion stability. The vice slug underwent a comparable examination, with surfactant concentrations varying between 0.1% and 0.4%. The best balance between surfactant cost and recovery performance was provided by the ideal concentration of 0.15%. Beyond this point, increasing concentration produced only modest recovery improvements, suggesting an economic barrier. The modeling results were validated by core flooding tests with synthetic heterogeneous rock cores. The calculated results agreed with the experimentally optimized surfactant concentration levels, which were 0.3% in the main slug and 0.15% in the vice slug. With an additional increase of more than 24% above waterflooding, the trials' greatest recovery factor was 81.56%. (Huang and others, 2017)

The impact of eight important reservoir and operational parameters, including salinity, oil viscosity, reservoir thickness, permeability, connate water saturation, and temperature, on oil recovery in an oil-wet limestone reservoir was assessed in a different study using a fractional factorial design. According to their findings, ASP flooding performed better than polymer flooding in terms of recovery factor across 64 simulated scenarios, with gains in oil recovery exceeding 10% in some instances. Connate water saturation was the measure that had the biggest impact on oil recovery; lower values resulted in noticeably larger recovery factors. Furthermore, it was shown that whereas oil viscosity had a larger impact in polymer flooding situations, the interaction impacts of factors like thickness-permeability ($H \times K$) and permeability-angle ($K \times \text{Angle}$) were very significant in ASP flooding. Additionally, the study generated high-fidelity regression models ($R^2 > 0.97$) for polymer flooding and ASP that could forecast oil recovery depending on input factors. These results confirm CMG-STAR5 as a reliable method for scenario analysis and predictive modeling of ASP performance and highlight the necessity of meticulous multi-parameter

optimization in chemical EOR design. In 2018, Firozjahi et al. Coupling CMG simulations with optimization methods has been investigated in other publications. For example, Shurong et al. (2018) used Iterative Dynamic Programming (IDP) to improve ASP slug designs by integrating the findings of the CMG-STARS simulation into a biorthogonal spatial-temporal Wiener model. The efficiency of data-driven surrogate modeling for operational decision-making was demonstrated by their methodology, which yielded findings that were within 0.2% of the Net Present Value (NPV) that the full-physics simulation had predicted. These and other studies demonstrate that CMG-STARS is a dependable tool for developing and refining EOR methods in heterogeneous reservoirs because it can faithfully model the fluid dynamics, adsorption, and chemical transport of ASP floods. However, thorough calibration of model parameters including IFT reduction tables, adsorption isotherms, and relative permeability modifiers, as well as high-quality laboratory input data, are still necessary for effective implementation.

3. Methodology

3.1 CMG overall

Based on thorough geological research, a beautiful 3D geological model was created and a realistic development plan was created to guarantee the seamless development of a reservoir numerical simulation. In petroleum engineering, ASP (Alkaline–Surfactant–Polymer) flooding—an advanced chemical Enhanced Oil Recovery (EOR) technique—is modeled using the widely used compositional simulator CMG-STARS (Computer Modelling Group – Steam, Thermal, and Advanced Processes Reservoir Simulator). Engineers may use CMG-STARS to model the intricate interactions between a variety of chemical and physical processes that are involved in ASP processes, including as phase behavior, alkali-rock reactions, surfactant and polymer adsorption, interfacial tension (IFT) reduction, and non-Newtonian fluid flow. Users may simulate actual field conditions by defining chemical slugs, reaction kinetics, and transport processes using keyword-driven input and specialized PVT models. Shear-thinning viscosity models and adsorption isotherms are used to mimic polymer flooding behavior, whereas surfactant and alkali effects are handled by explicitly specifying IFT reduction tables as a function of chemical concentration and salinity. Additionally, CMG-STARS offers precise control over factors related to the rock-fluid interaction, including chemical retention, wettability adjustment, and relative permeability modification.

In heterogeneous formations with intricate fluid-rock interactions, these tools allow reservoir engineers to carry out sensitivity analysis, slug design optimization, and history matching. CMG-STARS provides a high-fidelity environment to predict oil recovery, assess economic feasibility, and reduce risk in ASP flooding operations, whether it is used to simulate pilot experiments or full-field deployment. For chemical EOR applications, it is therefore an essential tool for field development planning as well as research. To achieve a thorough numerical simulation of an oil reservoir, the CMG parallel simulator may immediately enter the findings of reservoir descriptions into several modules. These modules can then be returned to the geological modeling program at the same time. The model may be processed and calculated using the CMG program. Complex structural oil and gas reservoirs can be handled by it. The data processing function is robust, and the final answer is stable. The oil field's chemical flooding and thermal recovery can be replicated using the STARS module. It has a better simulation effect than other numerical simulation tools, particularly in the following areas:

(1) It has a flexible component model, a phase equilibrium constant model, a function model, a saturation function model, and a flexible good geological mechanic's model of the simulator. The user can use this software to simulate various chemical flooding processes;

(2) The physicochemical mechanism in the process of chemical flooding can be fully described by it. It can simulate the change in the polymer's molecular weight, shear, permeability, degree of mineralization, adsorption, and retention, permeability decrease, inaccessible pore volume, non-Newtonian fluid, polymer degradation, capillary number equation, interfacial tension, dispersion and diffusion components, ion exchange reaction, emulsification, etc. The selection of the chemical agent, the development method's optimization, the study of the oil displacement mechanism, the chemical flooding simulation, and other processes may all be employed to mimic the size of the laboratory to that of the mine. It was selected the CMG program as the numerical simulator software based on the study above.

3.2 Reservoir Model

The model's reservoir characteristics and fluid properties are used from the Kashagan oil field located in West Kazakhstan. Reservoir characteristics are presented in tables 2, 3, and 4. The information from table 2 is retrieved from GeoExpro company and shows the average reservoir

characteristics with the basic model requirements. Table 3 values show some of reservoir characteristics by layer distribution. The values are taken randomly but the average agreed with table 3 values (GeoExpro, 2013). Table 4 shows the volumetric composition of the reservoir before production. The formation pore volume and volumes of each phase component is obtained by CMG calculations itself.

Table 2. Average reservoir characteristics

Reservoir Model Parameters	Value
Grid Dimensions I*J*K	15*15*7
Cell Dimensions I*J (ft)	50*50
Initial Reservoir Pressure (psi)	3700
Initial Reservoir Temperature (F)	194
Average Porosity (Single Porosity Model)	0.2
Average Grid Thickness (ft)	14.3
Average Porosity	0.20
Average Permeability (mD)	100
Average Initial Oil Saturation	0.41

Table 3. Reservoir characteristics by layers

	Grid Thickness (ft)	Porosity	Permeability (I,J,K) (ft)	Oil Saturation	Water Saturation
Layer 1	5	0.26	160	0.7	0.3
Layer 2	10	0.22	130	0.65	0.35
Layer 3	15	0.20	120	0.6	0.4
Layer 4	15	0.20	100	0.4	0.6
Layer 5	10	0.18	80	0.35	0.65
Layer 6	20	0.18	60	0.2	0.8

Layer 7	25	0.16	50	0	1
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Table 4. Fluid volumes in the reservoir

#	Item	Units	Value
1	Gross formation volume	ft ³	1.1250E+08
2	Formation pore volume	ft ³	2.1263E+07
3	Aqueous phase volume	ft ³	1.3736E+07
4	Oil phase volume	ft ³	7.5267E+06
5	Gaseous phase volume	ft ³	0.0000E+00

Well pattern was chosen to be a normal 5-spot pattern with 1 producer at the center of the reservoir (seen from I-J side) and 4 injectors at each corner of the rectangular model (seen from I-K and J-K sides), which can be seen in figures 7 and 8 respectively.

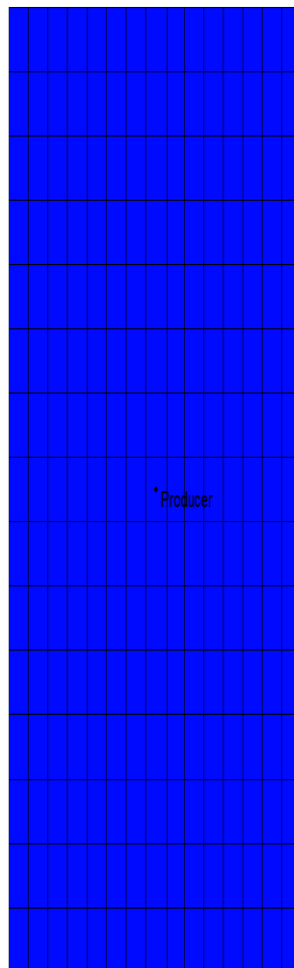


Figure 6. Producer location in the reservoir model

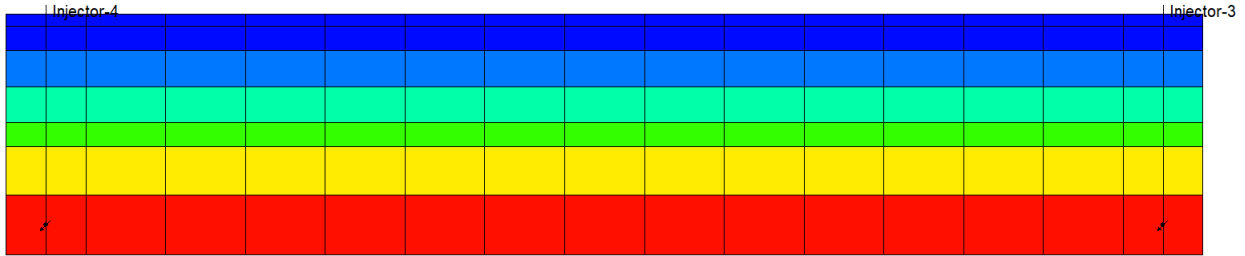


Figure 7. Injectors 3 and 4 from J-K perspective in the reservoir model

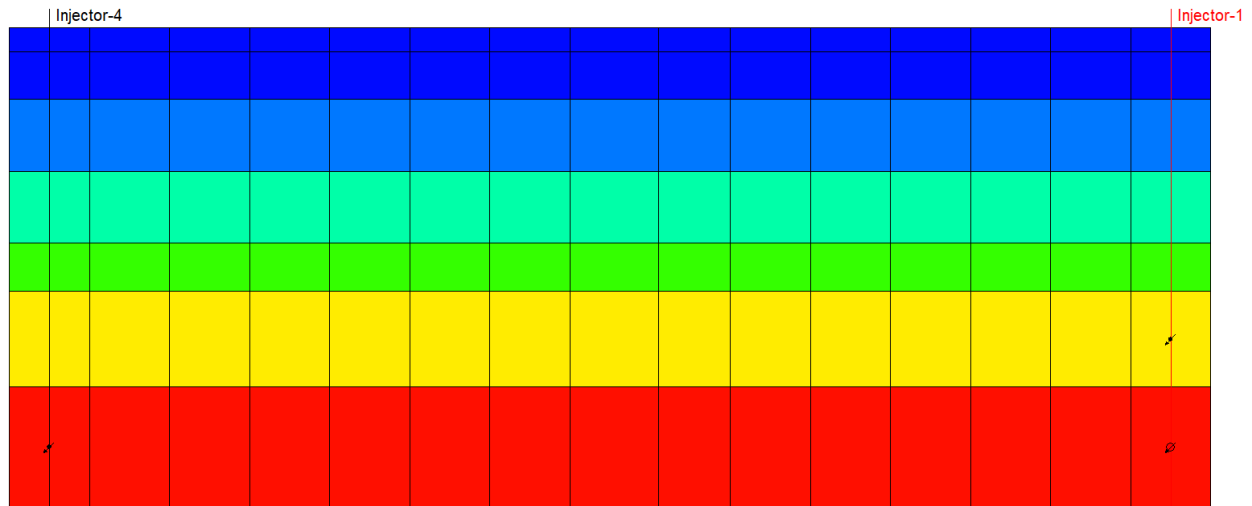


Figure 8. Injectors 1 and 4 from I-K perspective in the reservoir model

The injection rate is constrained by operator and STW surface water rate of 500 bbl/day per injector with salinity of 35 000 ppm. The production rate is constrained by operator and STO surface oil rate of 750 bbl/day. The model of normal 5-spot well pattern is presented in figure 10, along with porosity distribution in the reservoir.

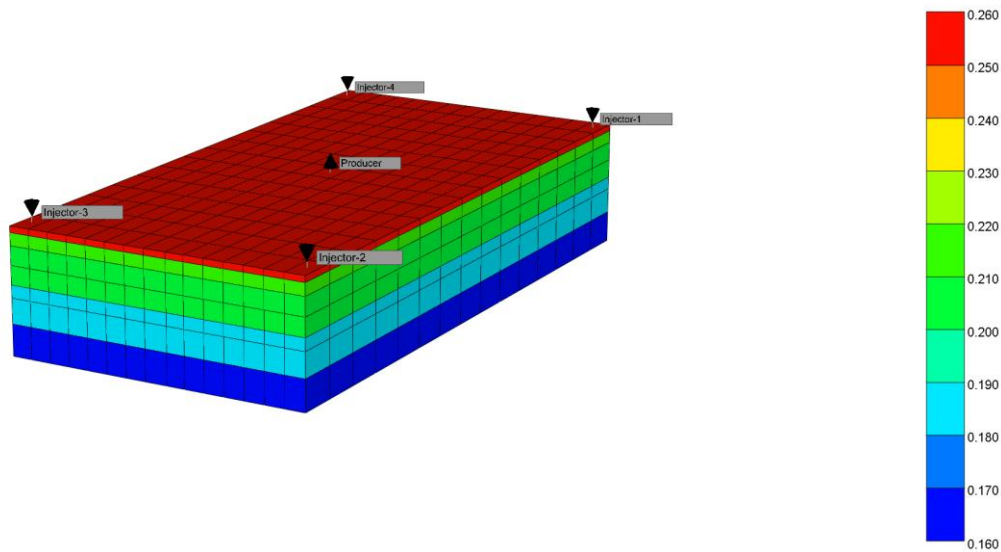


Figure 9. Well pattern representation

It was chosen to use depth-average capillary-gravity method as vertical equilibrium calculation method. Reference pressure is set up as 3000 psi. The location for reference pressure, i.e., reference depth is 2000 ft. Injection fluid consists of water, polymer, alkali, surfactant, and sodium chloride, its composition is described in figure 10.

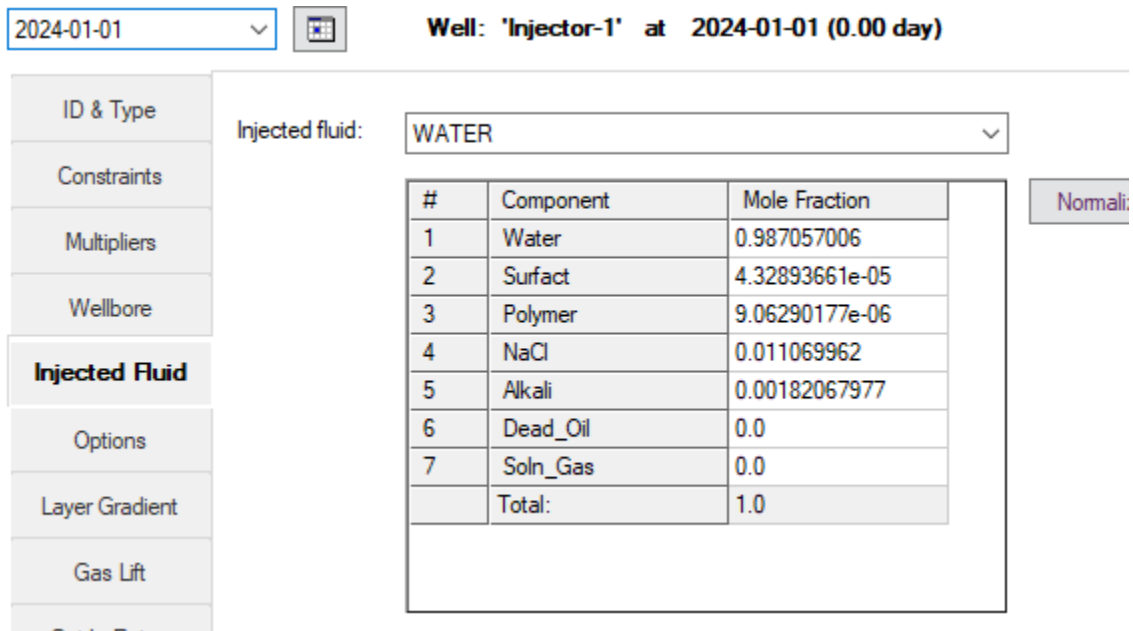


Figure 10. Injection Fluid composition

3.3 Fluid Properties

Oil properties are used from two papers and described in Table 6 and 7 (Ibray et al., 2011; Akhmedzhanov et al., 2012). Table 5 and figure 11 shows the composition of Kashagan oil by mass percent. Kashagan oil is light weight and contains high percent of hydrosulfide gas.

Table 5. Kashagan oil composition

Component	Primary
H ₂ S	11.9534970032327
C ₅ +	44.9379586587695
CO ₂	1.76562237192988
CH ₄	19.7727018098586
C ₂ H ₆	9.88635090492929
C ₃ H ₈	7.19007338540312
NC ₄	4.49379586587695
Sum	100

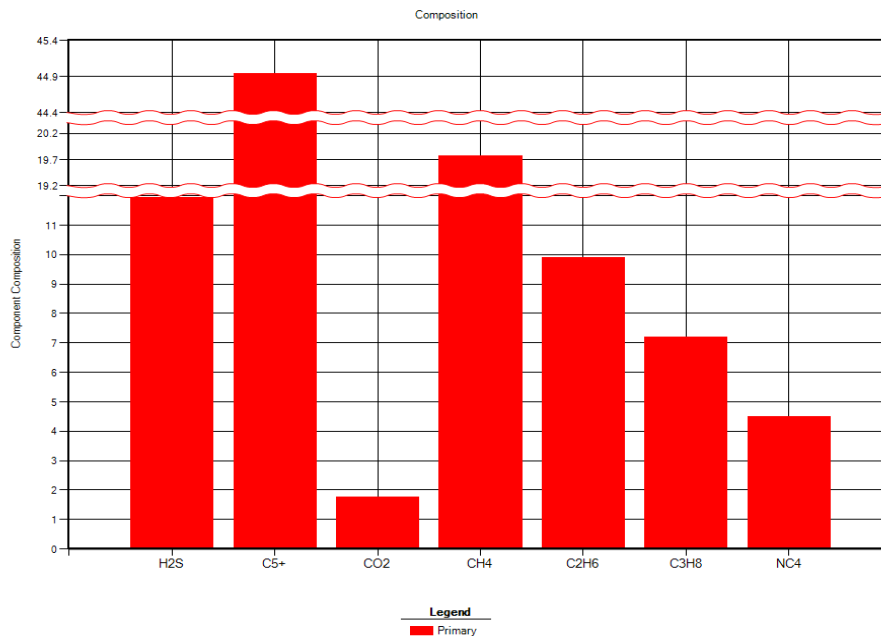


Figure 11. Kashagan oil composition

Table 6 shows the fluid properties of the reservoir. It is seen that the oil is light, with viscosity of 1.13 cp, which will be important in further discussion.

Table 6. Reservoir fluid properties

Fluid Properties	Value
Components Simulated	Oil, water, polymer, salt, alkaline, surfactant
Oil viscosity (cP)	1.13
Oil Density (g/ml)	0.835
Formation Volume Factor (rb/stb)	1.14
API Gravity	44
Specific Gravity	0.82
Oil Type	Light Oil
Bubble Point Pressure (psig)	993
Reservoir Salinity (ppm)	180 000

The reference pressure from component modeling is standard conditions pressure of 14.7 psi and temperature of 60 F. To mimic the Kazakhstani reservoirs, the formation water (FW) composition was kept the same as the Tengiz field formation water, with a salinity of around 180,000 ppm (Isabaev, 2015). The South Caspian seawater (CSW) was used for conventional waterflooding, having a salinity of 13,000 ppm (Tuzhilkin et al., 2005). Component property plots added in figure 12.

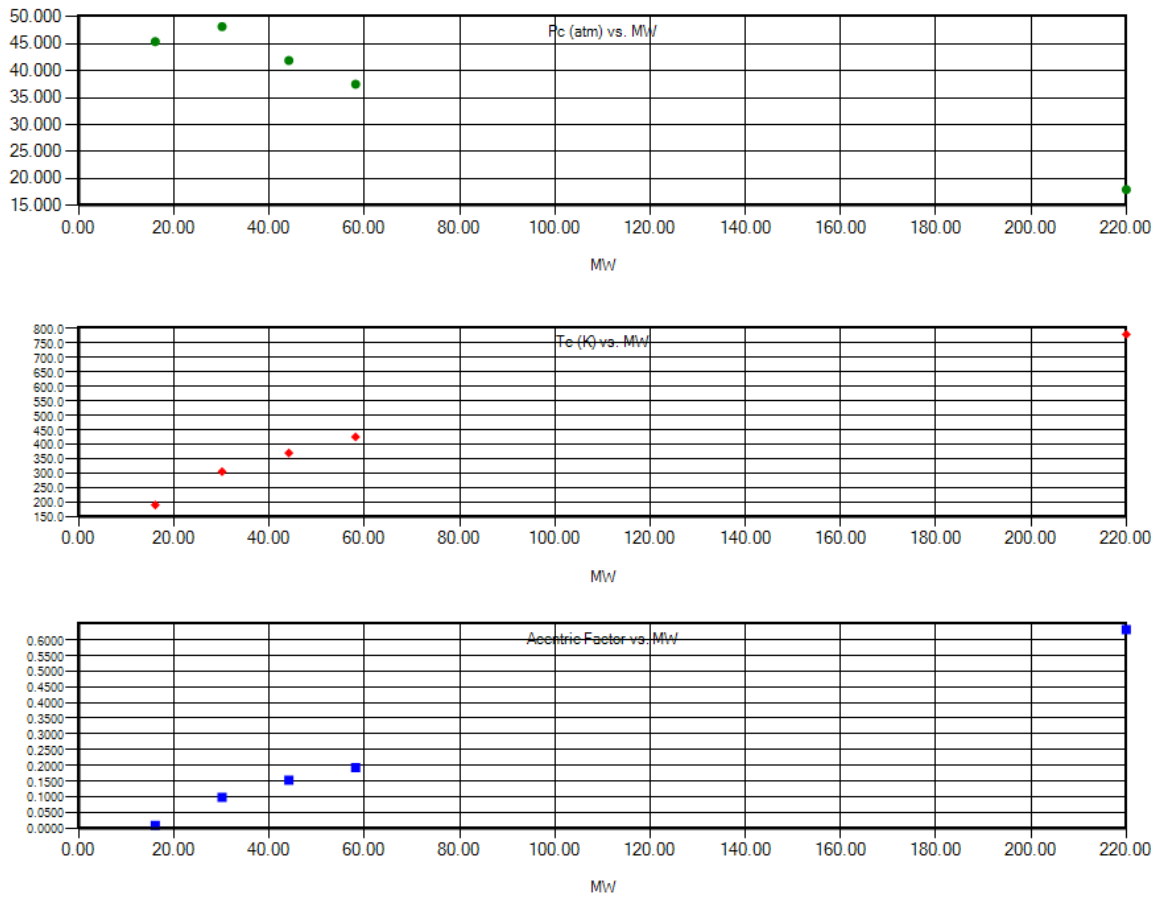


Figure 12. Component Property Plot

Table 7 represent the rock-fluid properties of the system. Due to the absence of this information in the open sources about Kashagan oil reservoir, these values are taken as generally used numbers.

Table 7. Rock-fluid properties

Property	Value
SWCON	0.2
SWCRIT	0.2
SOIRW	0.4
SORW	0.4
SOIRG	0.2

SORG	0.2
SGCON	0.05
SGCRIT	0.05
KROCW	0.8
KRGCL	0.3
KRWIRO	0.3
KROGCG	0.8
All Exponents	2.0

The produced relative permeability curves are seen in figure 13. Red line shows the dependence of water relative permeability and water saturation, while blue curve shows dependence of oil relative permeability and water saturation.

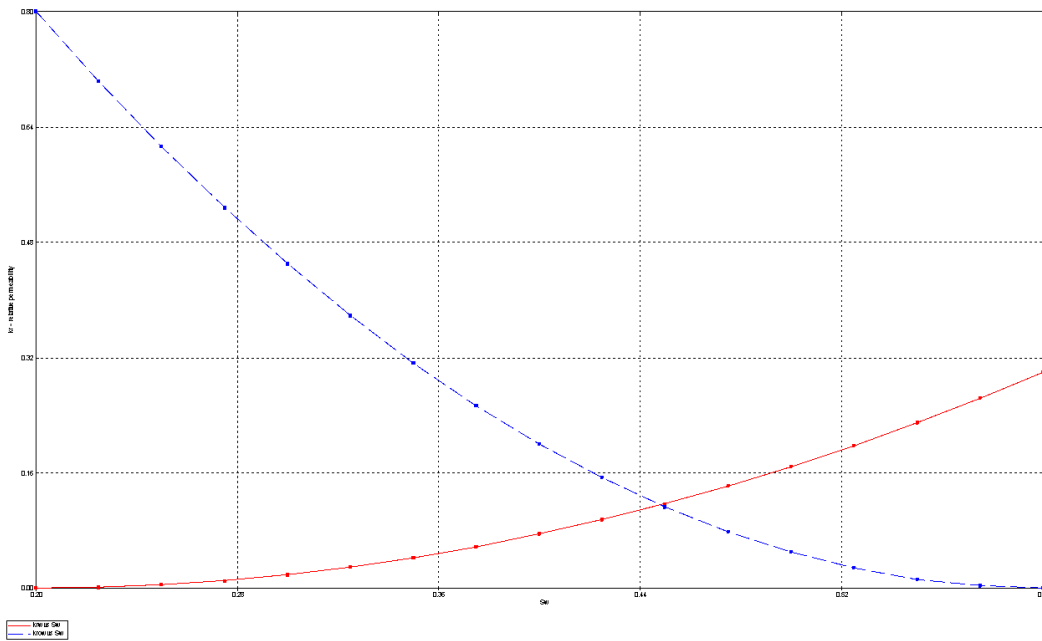


Figure 13. Water and oil relative permeability curves.

The relation of oil viscosity and temperature at constant pressure of 4900 psi is seen in figure 14. It is noted that with temperature increase the viscosity of oil decreases.

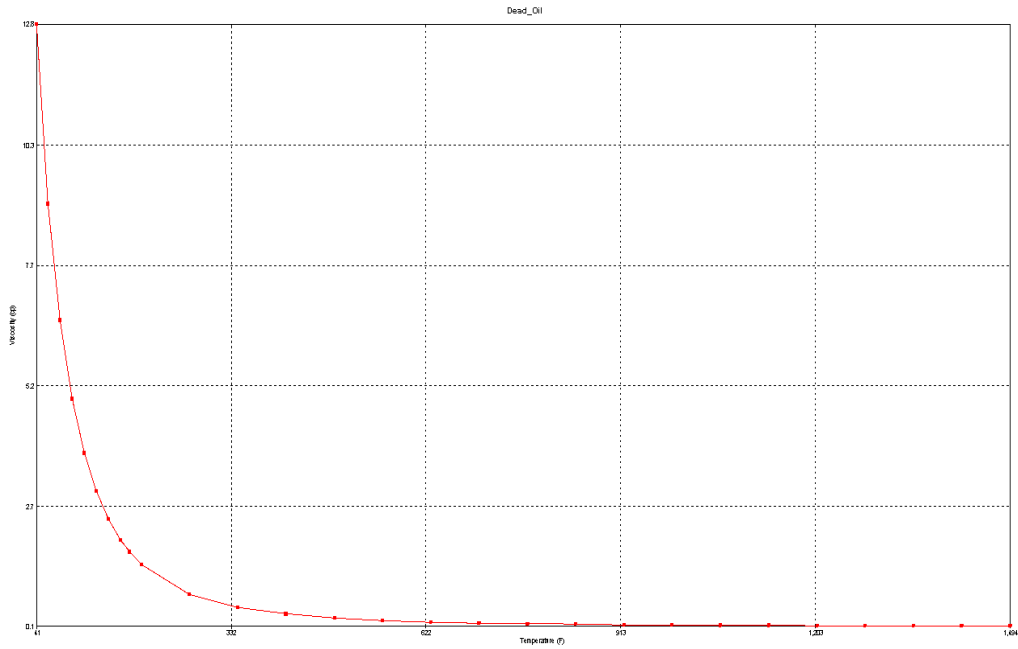


Figure 14. Oil viscosity vs Temperature at 4900 psi

Figure 15 shows the relation of oil density and pressure. Before bubble point, as pressure decreases oil density decreases too, however, after bubble point the consequent decrease in pressure results in increase of oil density, which is related to escaping of gas from the oil solution.

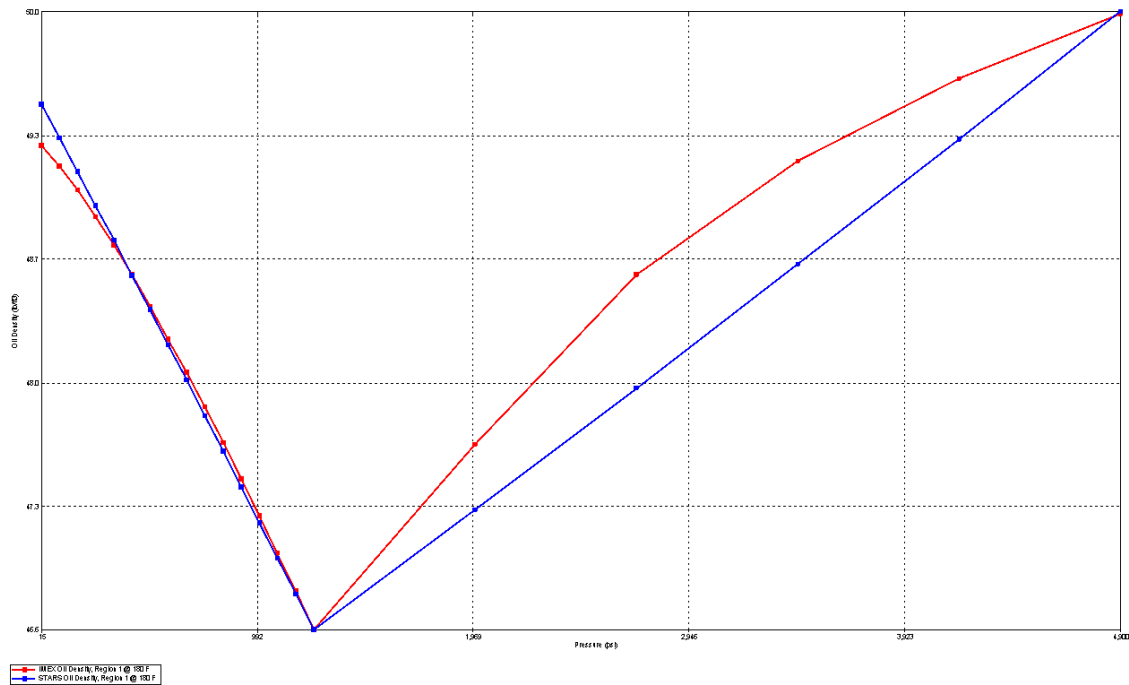


Figure 15. Oil density vs. pressure

3.4 Alkali, Surfactant, and Polymer Models

3.4.1 Polymer

Before the chemical modeling the permeability interpolation options are defined in table 8.

Table 8. Relative permeability interpolation options

Relative Permeability Interpolation Options	
Number of relative perm. sets for interpolation	3
Sorw reduction (Sorw_EOR/Sorw_WInj) for rel. perm. set #2	0.5
Krw change (Krw_EOR/Krw_WInj) for rel. perm. set #2	2

The polymer model was constructed using STARS CMG tool called Process Wizard. Most of the variables are taken as default, while some of them are used from Sorbie et al. (1982). Some of the most important simulation steps are presented in figures 16 and table 9. In figure 16 it is seen that molecular weight of polymer was chosen 8000 lb/lbmole. The effect of salinity on polymer adsorption was turn on. Also, Sor reduction is chosen due to the adsorption, rather than visco-elastic behavior. The half-life of polymer is set up as 1040 days, which is related to the rate of polymer degradation.

Select Options	
Polymer molecular weight (lb/lbmole)	8000
Polymer viscosity is a function of Salinity	<input checked="" type="checkbox"/>
SOR reduction due to polymer adsorption	<input checked="" type="checkbox"/>
SOR reduction due to polymer visco-elastic behavior	<input type="checkbox"/>
Enable polymer mobility reduction to restrict polymer flow into small pore t...	<input checked="" type="checkbox"/>
Permeability (md) below which polymer flow is restricted	1
Polymer flow restriction factor (0.0=no flow, 1.0=normal flow)	0
Polymer quantity decreases with time	<input checked="" type="checkbox"/>
Polymer half life (days)	1040
Polymer is adsorbed onto the reservoir rock	<input checked="" type="checkbox"/>
Make polymer adsorption dependent on salinity	<input checked="" type="checkbox"/>
Set initial reservoir water salinity (ppm)	40000
Use 2 waters (ResWater=immobile and Injwater) that gives faster breathr...	<input checked="" type="checkbox"/>

Figure 16. Polymer characterization

Figure 13 shows the polymer adsorption settings. The relationship between polymer concentrations, adsorption and the salinity show that with higher salinity and polymer concentration, polymer adsorption increases.

Table 9. Polymer adsorption settings

Rock type for conversion of adsorption val...	Limestone	
Rock Density, gm/cm3	2.71	
Enter all salinity(ppm) values in 1 cell	0 5000 15000	
Enter all alkali(wt%) values in 1 cell	0 0.3 0.6	
Polymer Adsorption		
Polymer resistance factor (1.0=no permea...	1.3	
Accessible pore volume for polymer adsor...	0.9	
Enter porosity of laboratory polymer adsorp...	0.2494	
Number of polymer concentration vs. adso...	2	
	Weight % Polymer	Polymer Adsorptio...
Alkali weight %= 0	0	0
Alkali weight %= 0	0.1	50
Alkali weight %= 0.3	0	0
Alkali weight %= 0.3	0.1	50
Alkali weight %= 0.6	0	0
Alkali weight %= 0.6	0.1	50

One of the important parameters in the table 9 is polymer resistance factor which is set up by 1.3 value. Polymer resistance factor is the ratio of the water mobility to the mobility of polymer (see equation 4). This factor is always greater than 1 and increase of this value is favorable for polymer flooding. In this project this value is made as default.

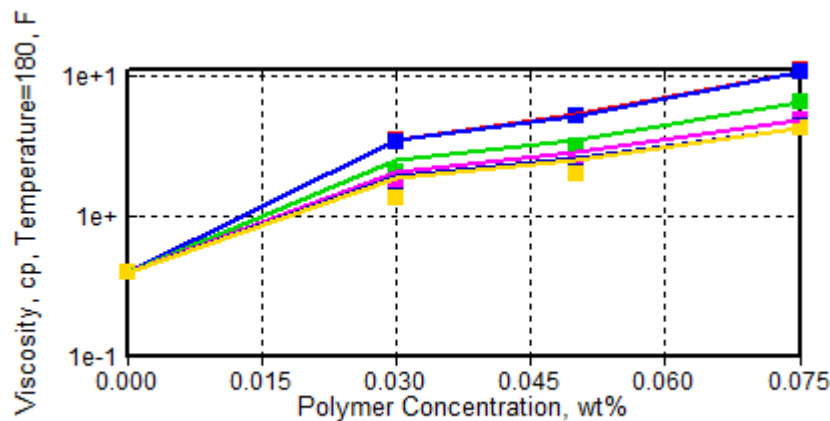


Figure 17. Viscosity alteration for different polymer concentrations

$$F_R = \frac{k_w \mu_p}{k_p \mu_w} \text{ Equation 4}$$

3.4.2 Alkali

In this work alkali is represented as sodium hydroxide, physical properties of NaOH are defined including density, solubility, molecular weight. Table 10 shows the dependence of IFT for surfactant with the concentration of alkali used. The graph formed from table 10, is seen in figure 18.

Table 10. IFT dependence from alkali concentration

	Select an IFT input option	IFT vs. Alkali ...		
	Enter all surfactant wt% values i...	0 0.01 0.05		
	Alkali wt% when IFT starts to in...	Set Value	Suggested va...	
	Weight % Alkali	IFT@ Surf=0	IFT@ Surf...	IFT@ Surf...
1	0	23.4	23.4	0.17
2	0.5	10.3	5.163	0.011
3	0.75	9.4	4.356	0.005
4	1	8.8	3.715	0.007
5	1.25	8.5	4.102	0.007
6	1.5	7.9	3.805	0.056

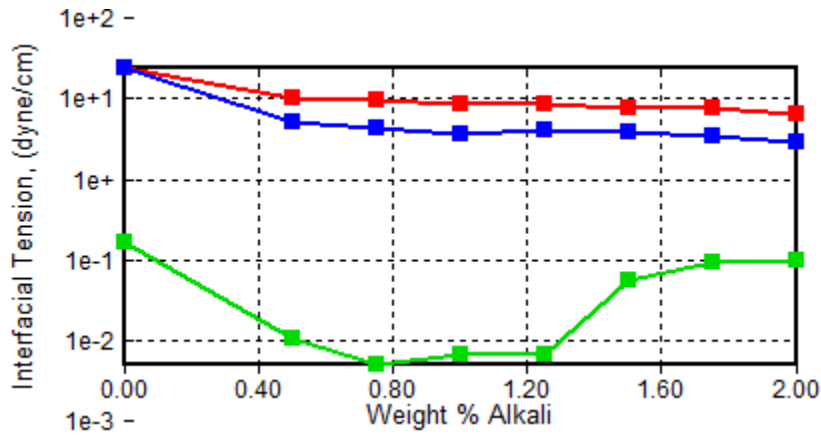


Figure 18. IFT dependence from alkali concentration

Table 11 shows the alkali adsorption depending on the alkali weight. The porosity of laboratory alkali adsorption along with alkali adsorption dependence with concentration are used as default values.

Table 11. Alkali adsorption settings

Alkali Adsorption		
Enter porosity of laboratory alkali adsorption...	0.2494	
Number of alkali concentration vs. adsorption...	2	
	Weight % Alkali	Alkali Adsorption, ...
Alkali weight %= 0	0	0
Alkali weight %= 0	0.1	50
Alkali weight %= 0.3	0	0
Alkali weight %= 0.3	0.1	50
Alkali weight %= 0.6	0	0
Alkali weight %= 0.6	0.1	50

3.4.3 Surfactant Modeling

Anionic surfactant is chosen to be used in the work. Possible anionic surfactants which can be used are alkyl aryl sulfonate, alkyl benzene sulfonate, alkyl sulfate, N-ethoxy sulfonate, alcohol propoxy sulfate, alpha-olefin sulfonate, which are the most typical surfactants used in the industry (Negin et al., 2017). Table 12 shows the surfactant adsorption depending on the surfactant weight.

Table 12. Surfactant adsorption settings

Surfactant Adsorption		
Enter porosity of laboratory surfactant adsorption...	0.2494	
Number of surfactant concentration vs. adsorption...	2	
	Weight % Surfactant	Surfactant Adsorption...
Alkali weight %= 0	0	0
Alkali weight %= 0	0.1	27.5
Alkali weight %= 0.3	0	0
Alkali weight %= 0.3	0.1	12
Alkali weight %= 0.6	0	0
Alkali weight %= 0.6	0.1	8.6
Surfactant adsorption is a function of time	<input checked="" type="checkbox"/>	
Surfactant adsorption rate/ADMAXT (1/day)	2.592	

The injection fluid composition is presented in table 13, where all values are written in weight %.

Table 13. Components for water injectors

Aqueous Components for Water Injectors	
Polymer injection wt%	0.075
Surfactant injection wt%	0.1
Alkali injection wt%	0.1
Salt injection (ppm)	13000

4. RESULTS AND DISCUSSION

4.1 ASP, polymer, and alkali-surfactant flooding comparison

All the results and further discussion are based on the predicting the cumulative oil production from 2024 to 2030 time period. In the figure 19 it is seen that highest oil production is achieved for ASP flooding with about 360 000 bbl, while lowest value is 285 000 bbl for alkali and surfactant flooding. Polymer flooding slightly underlies ASP performance with about 350 000 bbl of oil.

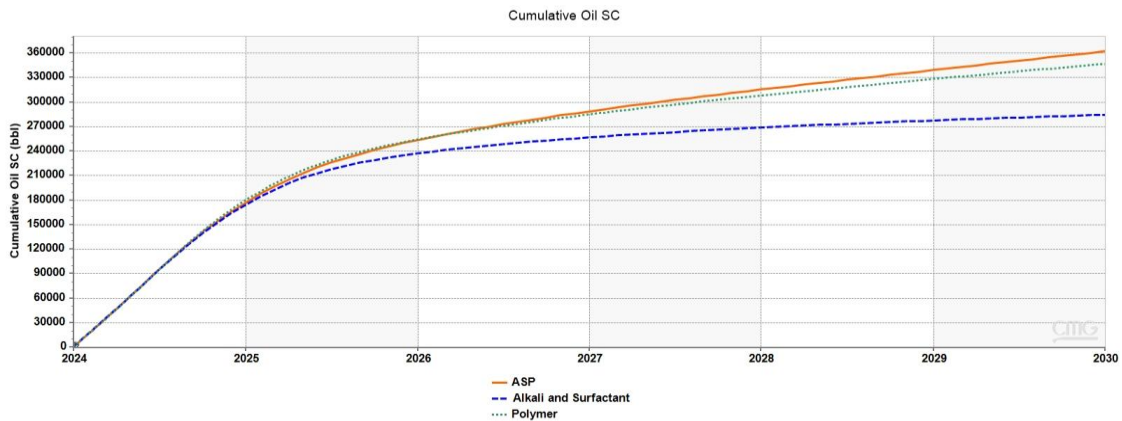


Figure 19. Cumulative oil production for polymer, alkali & surfactant, and ASP flooding

Graphs in figures 20 and 21 agree with cumulative oil production curve and shows highest water-oil ratio for alkali and surfactant flooding with WOR of 14, whereas at the end of period ASP flooding shows WOR of 11. Also, the lowest oil cut of 2% is seen for alkali and surfactant flooding, while the highest value is for ASP flooding of 5%

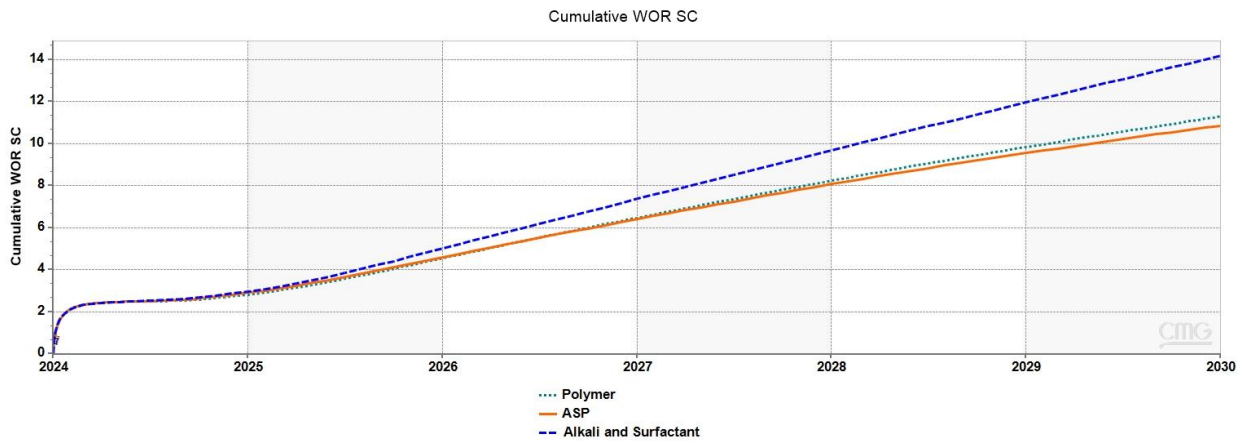


Figure 20. Cumulative water-oil ration for polymer, alkali & surfactant, and ASP flooding

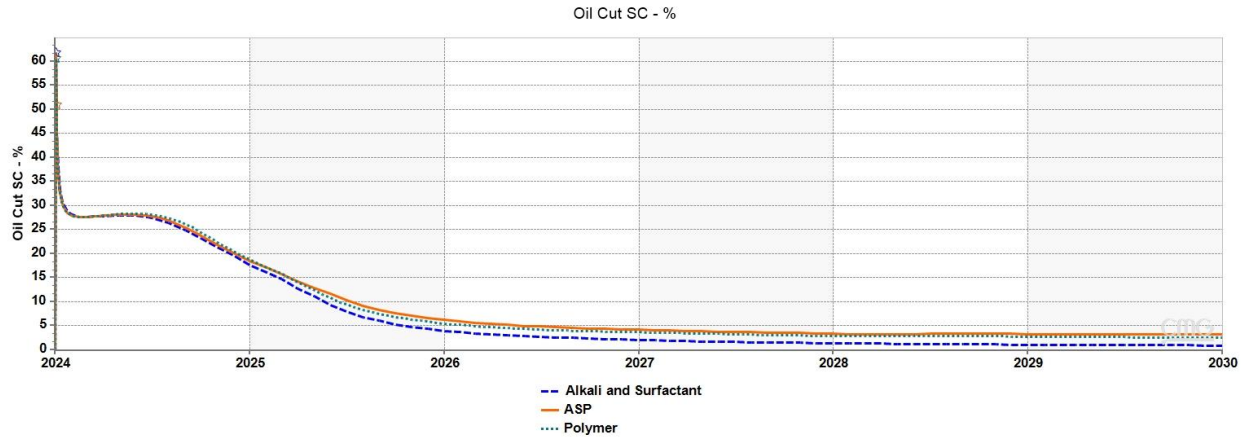


Figure 21. Oil cut in % for polymer, alkali & surfactant, and ASP flooding

4.2 Effect of salinity of injection fluid

The impact of injection water salinity on total oil output from 2024 to 2030 is seen in Figure 22. Based on the injection fluid's varying salinity levels, three scenarios are examined: low salinity (13,000 ppm), medium salinity (26,000 ppm), and high salinity (52,000 ppm). The total oil output in all three scenarios increases steadily, peaking between 2024 and 2026 and then gradually decreasing as the simulation period ends.

With a total oil production of about 360,000 barrels by 2030, the low salinity case (13,000 ppm) consistently produces the most oil out of the three scenarios. The high salinity scenario (52,000 ppm) has the lowest oil recovery during the simulation, whereas the medium salinity case (26,000 ppm) performs somewhat worse. With a final difference of around 10,000 to 15,000 barrels between the best- and worst-performing situations, the performance disparity becomes more noticeable after 2026.

These findings unequivocally show that lower injection salinity improves oil recovery efficiency, most likely because of decreased adsorption losses, enhanced chemical stability, and decreased polymer degradation. To maximize the efficacy of ASP flooding in high-salinity reservoirs, it is crucial to optimize the salinity levels in the injection fluid.

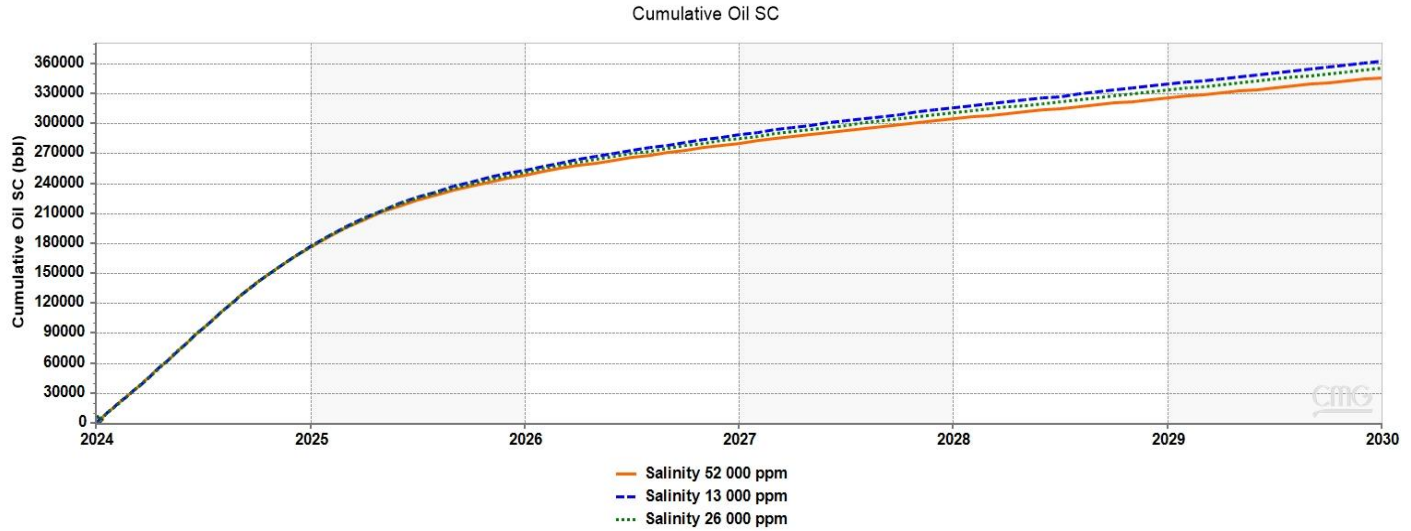


Figure 22. Cumulative oil production for different salinity levels

4.3 Effect of well placement

Four different well placement scenarios are performed in this work including normal 5-spot pattern, middle 5-spot pattern, normal 7-spot pattern, and middle 7-spot pattern. The presentation of normal 5-spot pattern can be seen in figure 9. Other well placements are shown in figures 23-25. 5-spot well pattern is described by one producer well in the middle of the reservoir and four injection wells forming squares, while 7-spot pattern include six hexagonal form injectors and one producer in the center.

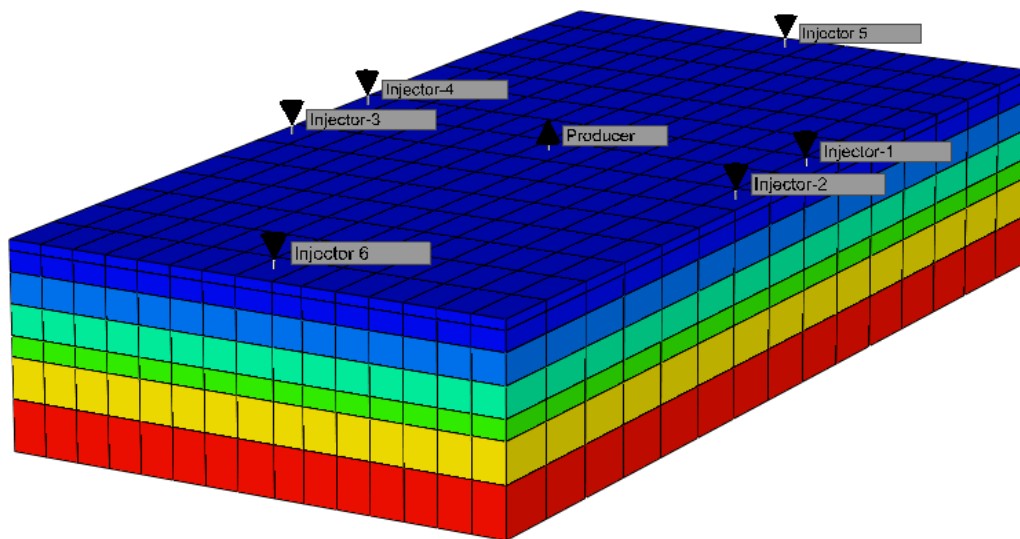


Figure 23. 7-spot normal well pattern

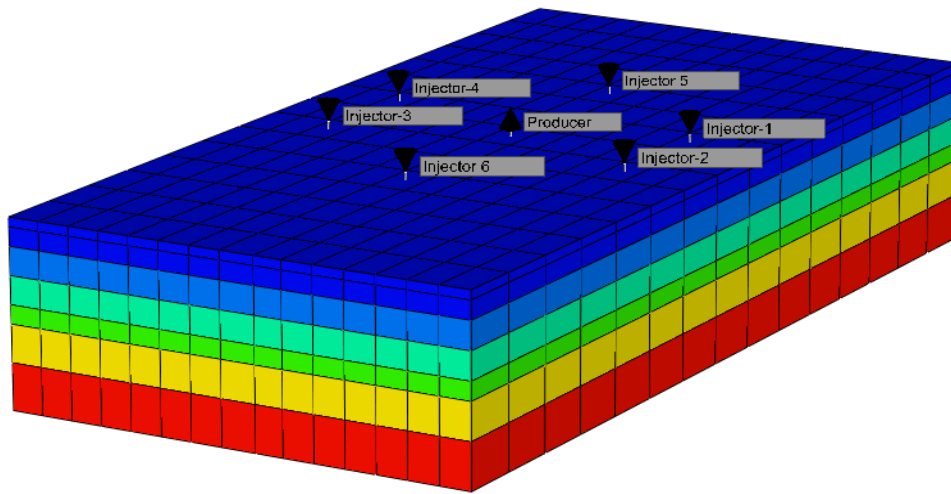


Figure 24. 7-spot middle well pattern

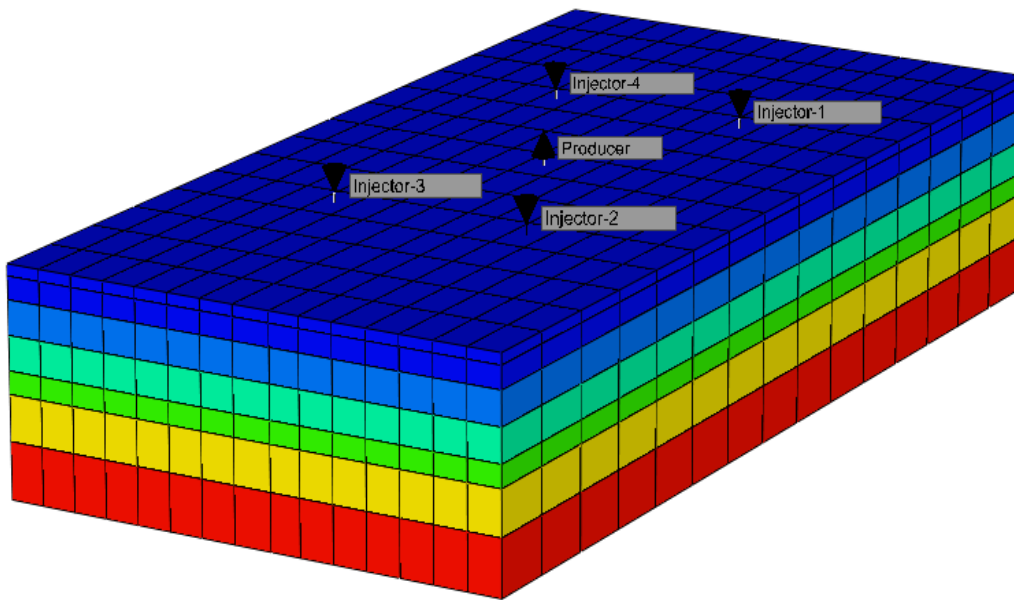


Figure 25. 5-spot middle well pattern

Figure 26 shows the cumulative oil production for four well pattern cases. Highest oil production is observed for normal 5-spot pattern with oil production 360 000 bbl, while the lowest production is achieved by 7-spot middle well pattern with production of approximately 210 000 bbl. Comparing the production performance of middle and normal well patterns normal well pattern

shows higher productivity results due to the better sweep efficiency. Also, comparing 5-spot and 7-spot patterns it is recommended to apply 5-spot well pattern with normal well placement to achieve higher oil production.

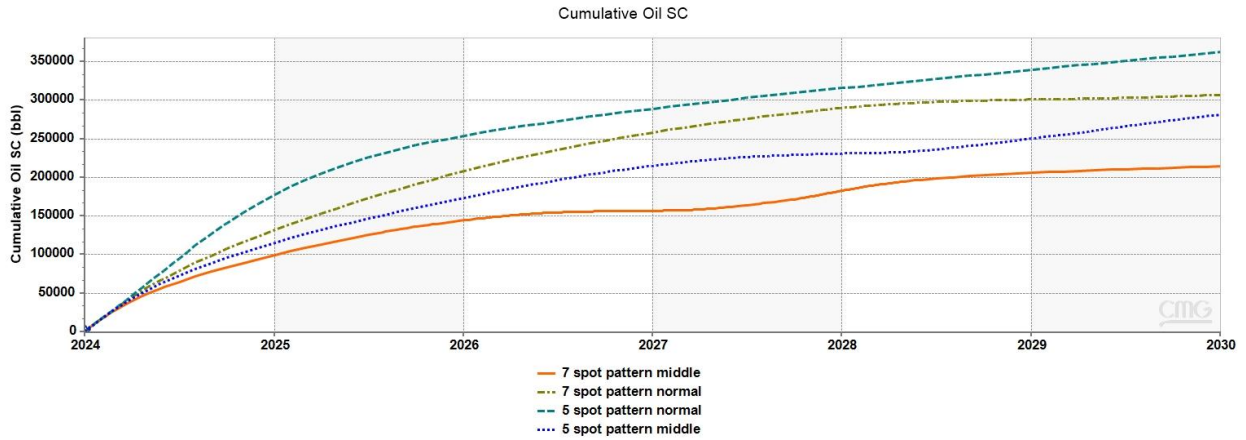


Figure 26. Cumulative oil production for different well patterns

4.4 Effect of polymer concentration

For polymer concentration sensitivity analysis three different polymer concentrations are used: 0.075, 0.0375, 0.0188 wt%. The highest oil production observed for 0.075 wt% polymer concentration showing direct relation with polymer concentration and oil produced (presented in figure 27). Compared to alkali and surfactant cases, in polymer sensitivity analysis the main 0.075 wt% polymer concentration is reduced by 2 and 4 factors, while for alkali and surfactant cases the concentrations are increased by these values. This is related to the error appearing if the polymer concentration is increased, since the time convergence in modeling cannot occur. This problem can be solved by modifying the porosity and permeability values, or reducing the bottom hole pressure, however these values must be constant for all cases for comparison reasons. The water cut results presented in figure 28 show similar results for each polymer concentration, showing the independency of polymer concentration and water-oil ration produced

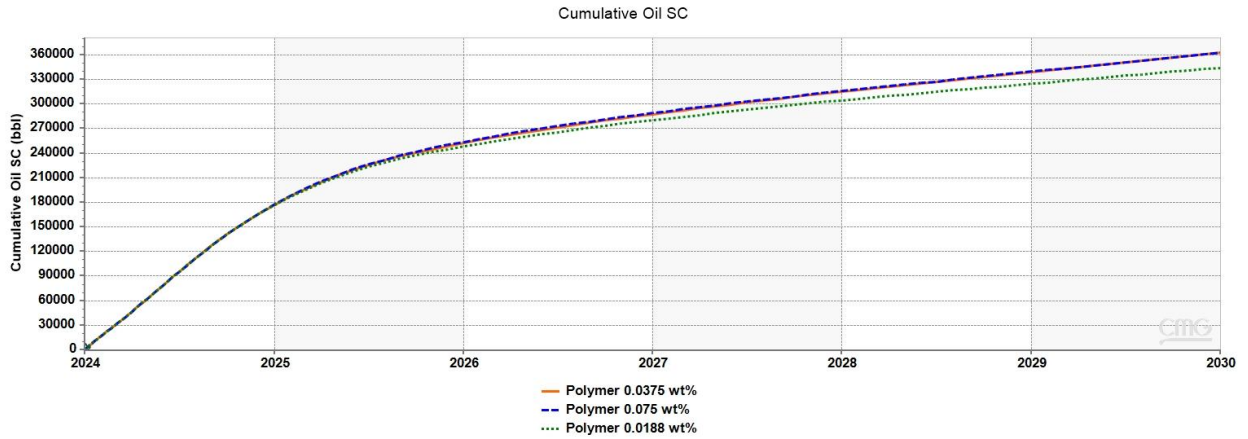


Figure 27. Cumulative oil production for different polymer concentrations.

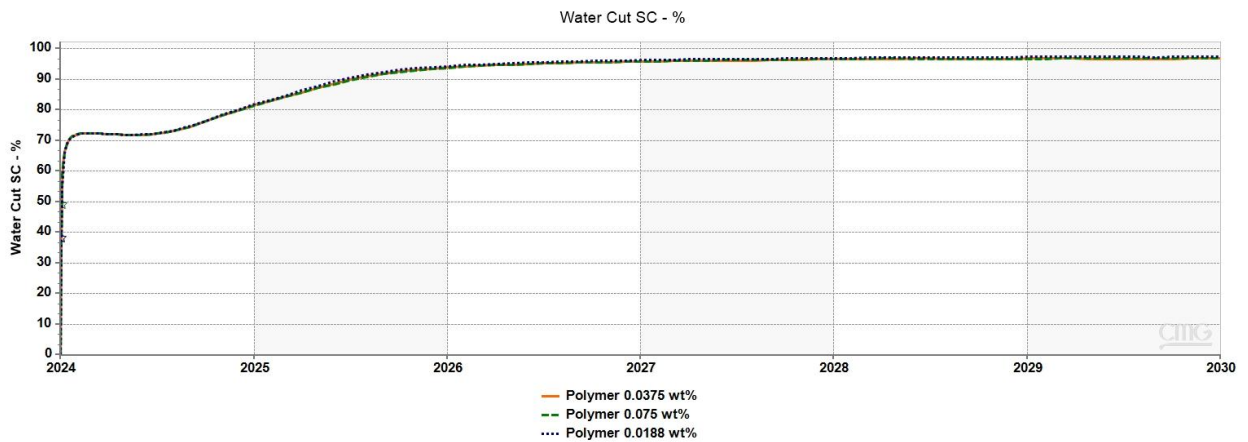


Figure 28. Water cut % for different polymer concentrations.

4.5 Effect of alkali concentration

The cumulative oil output for three distinct alkali concentrations—0.1 weight percent, 0.2 weight percent, and 0.4 weight percent—is displayed in Figure 29. Every example shows a consistent increasing trend, with the maximum recovery occurring at 0.4 weight percent. Compared to the about 370,000 barrels recovered at 0.2 weight percent and roughly 350,000 barrels at 0.1 weight percent, this scenario produces over 440,000 barrels at the conclusion of the simulation period in 2030. Higher alkali concentrations not only improve early-stage displacement efficiency but also maintain long-term recovery advantages, as seen by the performance gap's noticeable widening starting in 2026.

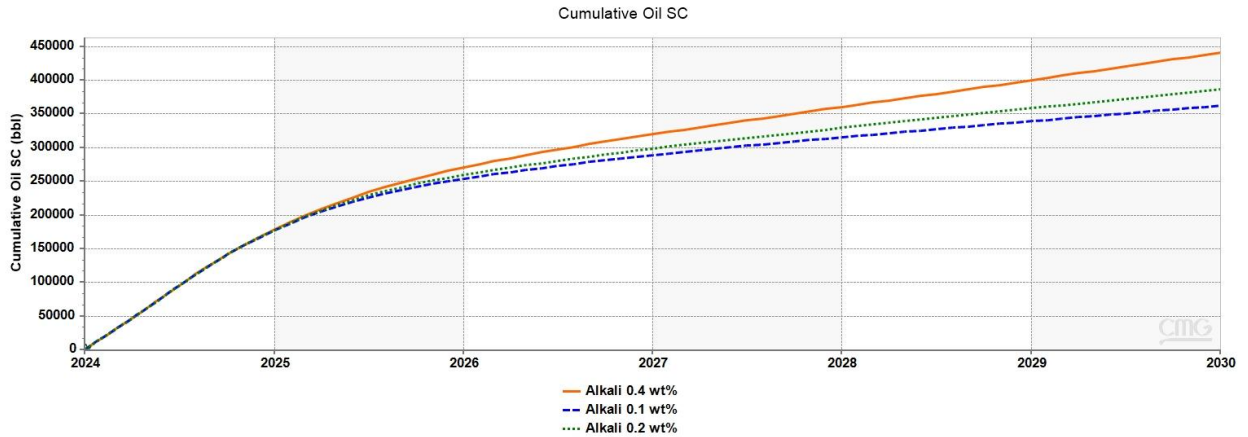


Figure 29. Cumulative oil production for different alkali concentrations.

For the same alkali concentrations, Figure 30 shows the percentage of water in the generated fluids. All three scenarios start off with a sharp increase in water cut, which levels off at about 70% in 2024. The curves start to slightly diverge in 2025. While the 0.1 wt% and 0.2 wt% instances achieve somewhat higher values, approaching 95%, the 0.4 wt% alkali example retains the lowest water cut, maintaining at 93% toward 2030. This implies that in addition to increasing oil production, a greater alkali content also slows water breakthrough and reduces water encroachment in the reservoir.

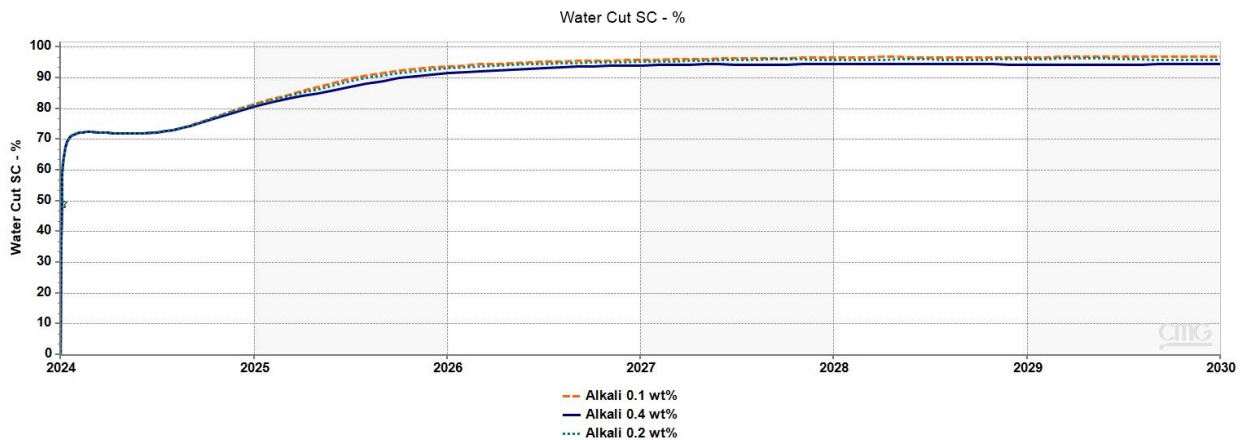


Figure 30. Water cut % for different alkali concentrations.

4.6 Effect of surfactant concentration

Cumulative oil output for three surfactant concentrations—0.1 weight percent, 0.2 weight percent, and 0.4 weight percent—is shown in Figure 31. During the initial years of production (2024–2025), the performance of each scenario is comparable. After 2026, however, variations start to show, with greater surfactant concentrations generally producing superior outcomes.

The scenario with 0.4 weight percent surfactant recovers the most oil by 2030, surpassing 400,000 barrels. This is followed by 0.2 weight percent and 0.1 weight percent, which yields the lowest recovery, at about 350,000 barrels. According to this pattern, a larger concentration of surfactant enhances displacement efficiency by more successfully lowering interfacial tension, which raises cumulative oil production.

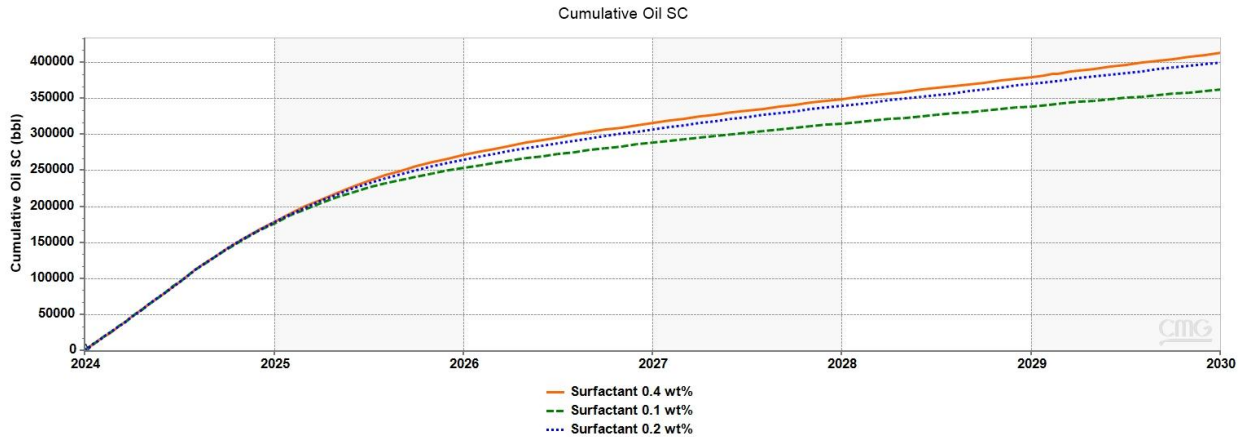


Figure 31. Cumulative oil production for different surfactant concentrations.

The water cut over time for the same surfactant concentrations is displayed in Figure 32. In the early stages of manufacturing, the water reduction in all three situations increases quickly at first, reaching almost 70% by the end of 2024. The curves progressively diverge over time. By 2030, the 0.1 weight percent surfactant case exhibits a slightly larger water cut, just above 95%, while the 0.4 weight percent case retains the lowest water cut, staying just below 94%. According to these findings, increasing the concentration of surfactants may assist to control water breakthroughs and sustain a marginally improved fluid production profile over time.

When combined, these data show that water cut behavior is marginally improved and cumulative oil recovery is positively impacted by rising surfactant content in ASP flooding. The economic trade-off must be taken into account, too, because the advantages of oil production often plateau around 0.2 weight percent, with declining gains in relation to the higher cost of chemicals.

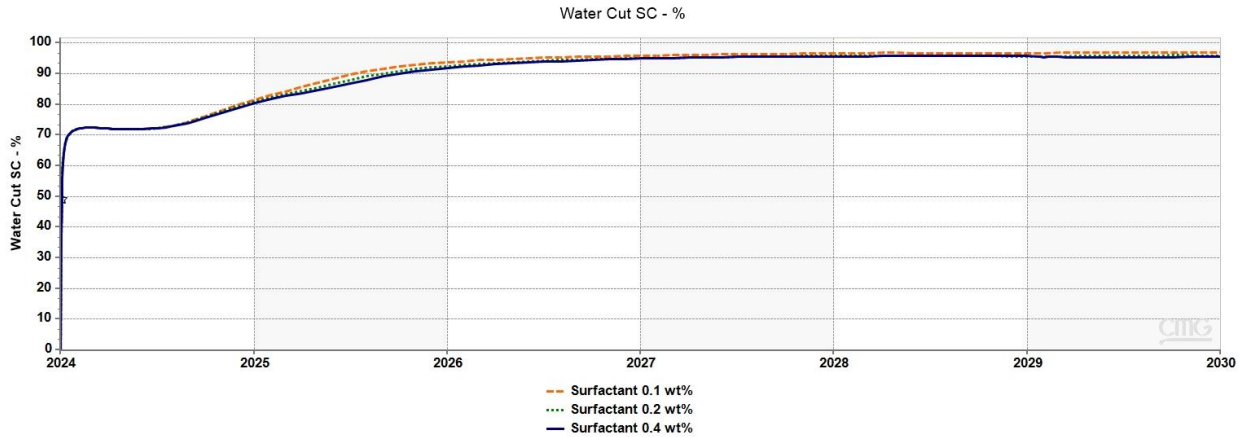


Figure 32. Water cut in % for different surfactant concentrations.

4.7 ASP Concerns and their solutions

Amine solutions can be used to address the issue of a high hydrosulfide concentration. H₂S and CO₂ are extracted from hydrocarbon gas using amine. Fresh, lean, or rich amine solutions indicate zero, low, or large quantities of absorbed acid gas in solution, respectively. At flow rates below 2 m/s and temperatures below 90 degrees, lean amine solutions do not corrode carbon steel when the amine breakdown product (heat stable salts) is absent. To prevent significant corrosion rates, the flow velocity for rich amine solutions should be limited to 1 m/s. Corrosion over 90 degrees is dependent on the kind and concentration of the amine as well as the partial pressure of the acid gases H₂S and CO₂.

Alkaline corrosion is another issue. Depending on their concentration and temperature, sodium hydroxide solutions can cause carbon steel to crack due to alkaline stress corrosion. Concerns about corrosion include localized corrosion (pitting and crevice), oxygen corrosion, galvanic effects, MIC, and chloride stress corrosion cracking. Regarding carbon steel, the estimated rate of corrosion is between 0.2 and 0.5 mm/y. Sacrificial aluminum anodes on the pump column will provide cathodic protection and coating for the outer surface of the pump column and the inner side of the caissons. Sacrificial aluminum alloy anodes will provide cathodic protection and a covering for the caisson's exterior. To prevent galvanic corrosion between coppernickel and superduplex pipes, use a lined spool or an electrical insulation kit. All of the sea water system's equipment is made of Monel 400, Nickel-Aluminum Bronze ASTM B148, or superduplex SS type 2507. Cupronickel 91/10 is the specification for the pipe (Akhmetzhanov et al., 2012).

4.8 Economic Analysis

The economic analysis of this project is based on calculation of pseudo-NPV value. Pseudo-NPV (NPV*) is described by the following equation:

$$NPV^* = V_o * P_o - M_p * P_p - M_a * P_a - M_s * P_s \text{ Equation 5}$$

Where,

V_o – volume of produced oil, bbl

M_p – mass of injected polymer, lb

M_a – mass of injected alkali, lb

M_s – mass of injected surfactant, lb

P_o – price of oil, \$

P_p - price of polymer, \$

P_a - price of alkali, \$

P_s - price of surfactant, \$

It is important to understand that pseudo-NVP value is not true value for evaluation the economy of the reservoir, but it is the comparable parameter between different cases of ASP application. While the other operating costs are held constant, the difference in the amount of chemicals used will decide which case is more economically preferable.

Table 14 shows the prices of oil, gas, polymer, surfactant, alkali, and injection rates of polymer. Price of oil is 67.34 \$/bbl from oilprice.com website for WTI CRUDE on 6/08/2025. The polymer price of 0.38 \$/lb was used for polyacrylamide from China region (IMARC, 2024). The alkali is sodium hydroxide (NaOH). The industrial price of 99% pure NaOH provided by Shandong Jinqi Chemical CO., LTD is on average 530 \$/ton or 0.24 \$/lb. The price of anionic surfactants (e.g., AOS 92%, AES/SLES) typically ranges from 0.36 \$/lb to 0.91 \$/lb with average 0.64 \$/lb when purchased in bulk FOB China. All prices of chemicals are based on the manufacturer prices and do not include operating expenses like shipping, taxes, and other expenditures.

Table 14. Component prices

Price of oil, \$/bbl	67.34
Polymer Price, \$/lb	0.38
Alkali Price, \$/lb	0.24
Surfactant Price, \$/lb	0.64

Value of oil produced are used from the early constructed time series plots, while the amount of injected chemicals is calculated by simple multiplication of injection fluid rate (from table XX) by total time of reservoir operation (6 years).

The amount of chemicals used at the whole period can be calculated as follows:

$$M_p = N_{ing} * R_{ing} * t * C_p \quad \text{Equation 6}$$

Where,

M_p is mass of polymer, Mlb

N_{ing} is number of injectors

t is time of operation, days

C_p is polymer concentration, wt%

$$M_p = 4 * 500 \text{ bbl/day} * 6 * 365 \text{ day} * 300 \text{ lb/bbl} * 0.00075 = 985.5 \text{ Mlb}$$

The mass of injected polymer with other concentrations and the masses of alkali and surfactant are calculated by the same way. All the results are presented in Table 15.

Table 15. NPV* values for different ASP compositions.

Composition	Oil Produced (Mbbl)	Polymer (Mlb)	Surfactant (Mlb)	Alkali (Mlb)	NPV* (MM\$)
Alkali (0.1%), Surfactant (0.1%), Polymer (0.075%)	360	985.5	1314	1314	22.7
Alkali (0.2%), Surfactant (0.1%), Polymer (0.075%)	390	985.5	1314	2628	24.4
Alkali (0.4%), Surfactant (0.1%), Polymer (0.075%)	440	985.5	1314	5256	27.2
Alkali (0.1%), Surfactant (0.2%), Polymer (0.075%)	400	985.5	2628	1314	24.5
Alkali (0.1%), Surfactant (0.4%), Polymer (0.075%)	420	985.5	5256	1314	24.2
Alkali (0.1%), Surfactant (0.1%), Polymer (0.0375%)	360	492.8	1314	1314	22.9
Alkali (0.1%), Surfactant (0.1%), Polymer (0.0188%)	340	246.4	1314	1314	21.7

NPV* values for each scenario can be calculated using the equation 5. The example calculation of the first composition case is presented as follows:

$$NPV^* = 67.34 * 360 - 0.38 * 985.5 - 0.64 * 1314 - 0.24 * 1314 = 22.7 \text{ MM\$}$$

Figure 33 is constructed based on the values from table XX. From this figure the highest NPV* value is seen for Alkali (0.4%), Surfactant (0.1%), Polymer (0.075%) cases when the polymer and surfactant concentrations are held constant with the main values, while alkali concentration is

increased by 4 times. The lowest NPV value case is the Alkali (0.1%), Surfactant (0.1%), Polymer (0.0188%), where polymer concentration is reduced by 4 times.

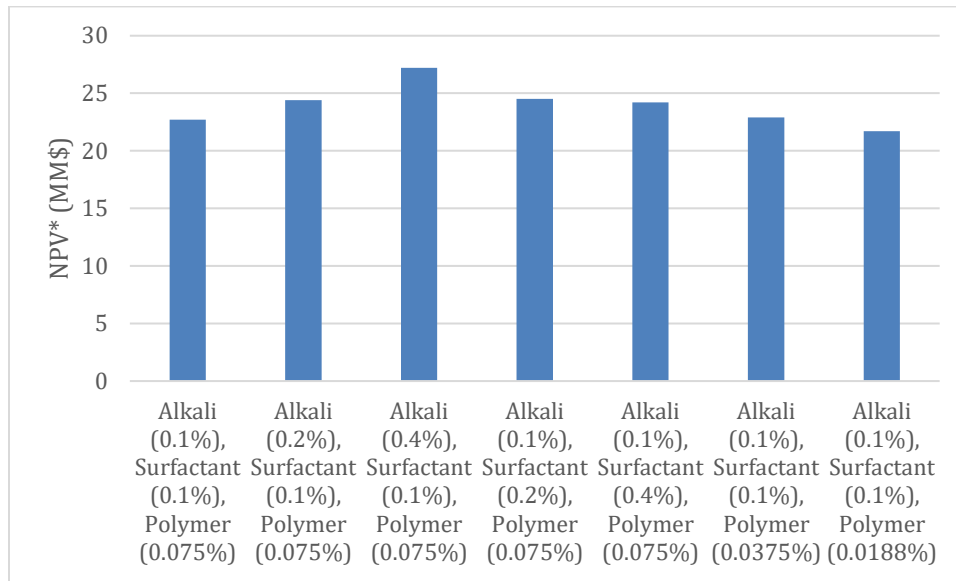


Figure 33. NPV* values for different ASP flooding compositions

The real practical effect of chemical editions must be considered with regards to economical aspect. For each chemical applied the increase in the concentration shows the rise in oil production, however NPV* values shows the real practical effect. For alkali case the increase in alkali concentration shows increase in NPV* value, however, for surfactant component highest NPV value is observed with 0.2 wt% concentration, after which further increase negatively affect the NPV* results. The similar behavior is observed with polymer, where the most effective case is seen when polymer concentration is 0.0375 wt% with NPV* of 22.9 MMS\$, which is slightly higher than the NPV* value for biggest polymer concentration (0.075 wt%).

5. CONCLUSIONS AND RECOMMENDATIONS

1. The CMG-STARS model successfully simulated ASP flooding in the Kashagan oil field, incorporating realistic reservoir conditions such as high salinity (180,000 ppm), light oil (API 44°), and good porosity (20%).

2. ASP flooding yielded the highest cumulative oil recovery (~360,000 bbl), outperforming both polymer-only (~350,000 bbl) and alkali-surfactant (AS) flooding (~285,000 bbl).
3. The normal 5-spot injection pattern achieved the best recovery (360,000 bbl), while the middle 7-spot pattern showed the poorest performance (210,000 bbl).

Sensitivity analyses for:

- **Polymer:** Maximum oil recovery was at 0.075 wt%, but 0.0375 wt% gave slightly better NPV* (\$22.9M).
- **Alkali:** Increasing from 0.1% to 0.4% improved both recovery (to 440,000 bbl) and NPV* (\$27.2M).
- **Surfactant:** The optimal concentration was 0.2%, producing the highest economic return (\$24.5M); higher concentration led to diminishing profitability.

4. ASP flooding provided superior economic performance compared to AS and polymer-only flooding.

5. The most cost-effective formulation consisted of 0.4% alkali, 0.1% surfactant, and 0.075% polymer, combined with a normal 5-spot pattern and low-salinity water, yielding the highest NPV* (\$27.2 million).

Recommendations

Based on the modeling insights and best practices documented in the literature, several technical techniques are suggested to further improve the performance and field applicability of ASP flooding in reservoirs like Kashagan. Prior to putting into practice any full-field ASP flooding scenario, history matching should be used. To make sure the model appropriately depicts reservoir behavior, simulation results must be calibrated against real-world field data, such as injection volumes, water cut patterns, and oil production rates. Using automatic optimization techniques is also advised. These might include Latin Hypercube Sampling, Design of Experiments (DOE), or more sophisticated algorithms like Genetic Algorithms. These methods may be used with integrated Python/Matlab programming environments or CMG's CMOST platform. Multi-variable sensitivity tests on injection rates, slug sizes, chemical concentrations, and timing sequences are made possible by automated optimization, which eventually improves decision-making and raises recovery factors.

Additionally, simulation time can be decreased without sacrificing prediction accuracy by using surrogate modeling approaches as biorthogonal spatial-temporal models or reaction surface methods.

For ASP flooding to be successful, the injection strategy's design is essential. It is advised to test different injection times as well as pre- and post-flush procedures. Each chemical component—polymer, surfactant, and alkali—can have its slug size adjusted to assist strike a compromise between economic viability and technical performance.

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