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Simulation Study of Preformed Particle Gel for Conformance Control

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Simulation Study of Preformed Particle Gel for Conformance Control

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Abstract

Simulation Study of Preformed Particle Gel for Conformance Control

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Conformance control has long been a compelling subject in improving waterflood oil recovery. By blocking the areas previously swept by water, subsequently injected water is allowed to sweep the remaining unswept portions of the reservoir and thereby increase the ultimate oil recovery. One technique that has received a great deal of attention recently in achieving this in-depth water shut-off is crosslinked gel injection. However, processing and predicting the performance of these gels in complex petroleum reservoirs is known to be extremely challenging. A model that accurately represents the reservoir features, chemical properties, and displacement mechanisms is, therefore, required.

In this study, we further developed the UT in-house numerical reservoir simulator, branded as UTGEL. Our first focus was to enable UTGEL to simulate a new type of temperature-resistant and salt-tolerant pre-crosslinked swellable particle gel, known as Preformed Particle Gel or PPG. A series of numerical simulations have been conducted to match with experimental data and generate parameters for full field scale simulation. Five laboratory experimental matching attempts were successfully performed using the UTGEL simulator in this study. The matched experiments included a fracture model, two sandpack models, a sandstone coreflood experiment, and a parallel sandpack model

The second focus of this study was to investigate the applications of PPG in blocking high-permeability layers, fractures, and conduits. A number of synthetic and actual field cases were generated to study the performance of PPG in (1) reservoirs with

various layered permeability contrasts, from extremely low to extremely high permeability contrasts, (2) reservoirs containing extensive conduits or channels, and (3) real field cases where heterogeneity had been identified unfavorable to the waterflood efficiency. The simulation outcomes indicated significant incremental oil recovery from PPG treatment ranging from less than 5% to almost 30%. A number of sensitivity analyses were also conducted to provide some insights on the optimal PPG treatment design.

Lastly, to enhance the capability of UTGEL in simulating gel transport in diverse scenarios, a novel Embedded Discrete Fracture Modeling (EDFM) concept was implemented into UTGEL in this study, allowing multiple sets of fracture planes and conduits with dip angles and orientations to be modeled and simulated with gel treatments for the first time with a rather computationally inexpensive method. Although the developed simulator requires further improvement and validation against wider reservoir and fluid conditions, the representative results from a number of generated models in this study have suggested another step forward towards achieving realistic reservoir modeling and advanced gel transport simulation.

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Chapter 1: Introduction

Sweep inefficiency has been identified as one of the most important reasons for lower-than-expected waterflood recovery. Oil-bearing rocks generally comprise many layers of varying permeability. During a waterflood process, layers with high permeability often perform as channels transporting a large fraction of displacing fluid (typically less viscous than oil i.e. brine, freshwater). Consequently, layers with lower permeability are not efficiently swept and the corresponding oil remains trapped.

Over the recent few decades, similar to many innovations adopted by the Oil and Gas industry, the practice of conformance control to improve waterflood sweep efficiency has been endorsed and has evolved greatly with advances in technology. Conformance control, although short-term in nature, can be more economical than typical Enhanced Oil Recovery or EOR applications. This is because conformance control assists in reducing water cut by effectively treating only minor areas of a high permeability zone; for instance, natural fracture conduits (Borling, 1994). Gel treatments have proven to be the new cost-effective methods for improving waterflood recovery by targeting both formation heterogeneity and an adverse mobility ratio. In fact, these treatments have been successfully applied in several mature fields encountering waterflood conformance problems; namely, Daqing Oilfield in China (Liu, et al., 2006), Minas Field in Indonesia (Pritchett, et al., 2003), and San Jorge Gulf of Argentina (Muruaga, et al., 2008).

Preformed Particle Gel, or PPG, is a new type of temperature-resistant and salt-tolerant pre-crosslinked swellable particle gel (Bai, et al. 2004, 2007, and 2013). Small amounts of these gels can be injected to block high permeability zones, divert the water to other regions of the reservoirs, and decrease the portion of bypassed oil. The distinct advantages of PPG involve its deeper penetration compared to bulk- or polymer gels and the ability to control its intrinsic properties (e.g. size, strength, and thermal stability) prior to injection, unlike other types of microgels.

Despite the straightforward concept, a successful gel treatment requires a comprehensive understanding of the reservoir and fluid parameters. The ability to model the behavior of injectants in-situ in a reservoir environment is necessary to optimize the treatment. In the past few years, such a capability has been developed with mathematical models proposed to characterize the propagation of gels in addition to typical fluids. However, previous works have only focused on polymer bulk gel (Kim, 1995), colloidal dispersion gel or CDG (Abdulbaki, 2012), and thermal/pH sensitive polymers (Onbergenov, 2012). Thus, an efficient model is desired to characterize PPG propagation through given reservoir formations.

In this research we present an inclusive simulation study of PPG behaviors from laboratory experiment history matches to field-scale simulations, not only in porous media but also through fractures and conduits. Opening with a literature review of conformance control and gel treatments, Chapter 2 describes the concept of waterflood sweep efficiency and how the reservoir heterogeneity creates a problem, which leads to the use of polymer, polymer gel, and preformed particle gel or PPG for conformance control. Chapter 3 provides a concise description of the developed in-house reservoir simulator used in this study, UTGEL. A gel transport module developed in particular for PPG simulation was also presented in this chapter. In Chapter 4, PPG simulations using UTGEL was validated by a series of experimental data obtained from the Petroleum Engineering laboratory at Missouri University of Science and Technology. In Chapter 5, synthetic field-scale cases were generated to analyze and evaluate PPG performance in diverse scenarios; namely, layered reservoir models with different permeability contrasts, and a couple of reservoir models containing large high permeability conduits. In Chapter 6, a variety of optimization studies of PPG treatments were finally performed with actual field data. The simulation results indicated that a well-designed PPG treatment could result in a significant increase in oil recovery, which was comparable to CDG and bulk gel treatments. However, further development works are required for further validation of UTGEL against wider ranges of reservoir and fluid constraints. A history match of an actual field performance of PPG treatment would highly benefit the study. Added as an extra chapter of this study, Chapter 7 presents a first-time integration of comprehensive gel transport modules and a novel discrete fracture modeling. By implementing a novel approach of Embedded Discrete Fracture Modeling (EDFM) into UTGEL, both (1) gel rheological and transport properties; such as shear thinning viscosity, adsorption, permeability reduction, and inaccessible pore volume, and (2) multiple sets of fractures with whichever dips and orientations were able to be captured all together in a numerical reservoir simulation. A number of synthetic cases were generated to verify as well as demonstrate the benefits of the incorporation of EDFM into UTGEL. The extensibility of this work could provide a further step in achieving better modeling of reservoirs and chemical treatments.

Chapter 2: Literature Review

To illustrate how gel technology is important in improving waterflood recovery, it is essential to understand the fundamental concepts of waterflood sweep efficiency, what the critical problem is, and why polymer and, later, gel technologies have been employed to improve waterflood recovery. This chapter reviews the importance of waterflood sweep efficiency; a brief summary of why polymer and gel are needed for conformance control; what are the difference between polymer, polymer gels, and microgels; and finally, preformed particle gels or PPG in specific.

2.1. Waterflood Sweep Efficiency

By far, the most widely used method for increasing oil recovery in petroleum industries has been waterflooding. In reservoirs with favorable mobility ratios, waterflooding can yield substantial incremental oil recovery when compared to primary depletion. A typical successful waterflood project can increase oil recovery from the range of 5% to 30% of the initial oil-in-place, which is normally seen under primary recovery, up to the range of 30% to 70% of the initial oil-in-place.

In waterflood reservoir management, one of the computed parameters typically used to define the effectiveness of the waterflood implementation is sweep efficiency (E). Sweep efficiency is a product of areal sweep efficiency (E_A), vertical sweep efficiency (E_I), and local displacement efficiency (E_D):

$$E = E_A E_I E_D \qquad \text{……………………………(2-1)}$$

Areal Sweep Efficiency (E_A**)** represents the fraction of area that the water contacts in the reservoir. It depends mostly on the degree of reservoir compartmentalization, waterflood pattern, and well spacing.

Vertical Sweep Efficiency (E_I**)** represents the fraction of a formation on a vertical plane that the water contacts in the reservoir. It depends primarily on the degree of reservoir stratification. Composition, porosity, and permeability of the strata can all effect vertical sweep efficiency. Thin, high permeability channels in stratified reservoirs can prevent efficient flooding of other zones. This results in lower oil production and increased water production.

Displacement Efficiency (E_D) relates to the amount of oil which water displaces in the invaded zone i.e. overcomes the capillary pressure that traps the oil which depends on interfacial contact.

The causes of poor sweep efficiency, which often results in early breakthrough, excessive production of water, and thus, low waterflood recovery, can be largely identified into two categories:

1. **Reservoir heterogeneity**

   The main challenge to oil recovery in waterfloods is reservoir heterogeneity. It is fundamentally any non-uniformity in a dynamic reservoir, including variability in permeability and porosity, anisotropy, fractures, faults, solution channels, interconnected vugs, karstic features, faults, and compartmentalization. Reservoir heterogeneity can be described as the quality of the medium which causes the flood front (the boundary between the displacing and displaced fluids) to spread as the displacements proceeds (Lake, 1989). The most popular means to express the heterogeneity of a reservoir is by calculating the Dykstra Parsons coefficient, a static measure based strictly on permeability variation. A reservoir is considered to be highly heterogeneous if a large fraction of the flow occurs in a small fraction of the pore space. In general, the Dykstra Parsons coefficient of any reservoir is in the range of 0.3-1.0 where the higher Dykstra Parsons coefficient correlates to the higher heterogeneity (Sahni, et al., 2005).

2. Unfavorable mobility ratio

Mobility ratio (M) is defined as mobility $\left(\frac{k}{\mu}\right)$ of the displacing phase (generally water) divided by the mobility of the displaced phase (generally oil). For waterfloods, the mobility ratio can be calculated as following:

$$M = \frac{Mobility_{water}}{Mobility_{oil}} = \frac{\left(\frac{k_w}{\mu_w}\right)}{\left(\frac{k_o}{\mu_o}\right)} = \frac{k_w \mu_o}{k_o \mu_w} = \qquad \text{……………………..(2-2)}$$

An unfavorable mobility ratio implies the situation where it is more favorable for the displacing fluid to flow compared to the fluid being displaced, for example, the displacing fluid has lower viscosity and higher relative permeability. A mobility ratio of value more than one is thus considered unfavorable and can lead to a non-uniform areal and vertical displacement or viscous fingering.

2.2. Polymer Technology

It is safe to say that all petroleum reservoirs are heterogeneous with varying degrees of heterogeneity. Therefore, the sweep efficiency of the waterflood can vary significantly between reservoirs. With the two causes mentioned previously, waterflood recovery can be, more often than not, lower than expected.

Polymer injection or polymer flooding was introduced primarily to further enhance the oil recovery from waterfloods by addressing adverse mobility ratio. Polymer flooding increases the viscosity of water and thus lowers the water mobility, which leads to increasing fractional flow of oil (Figure 2-1).

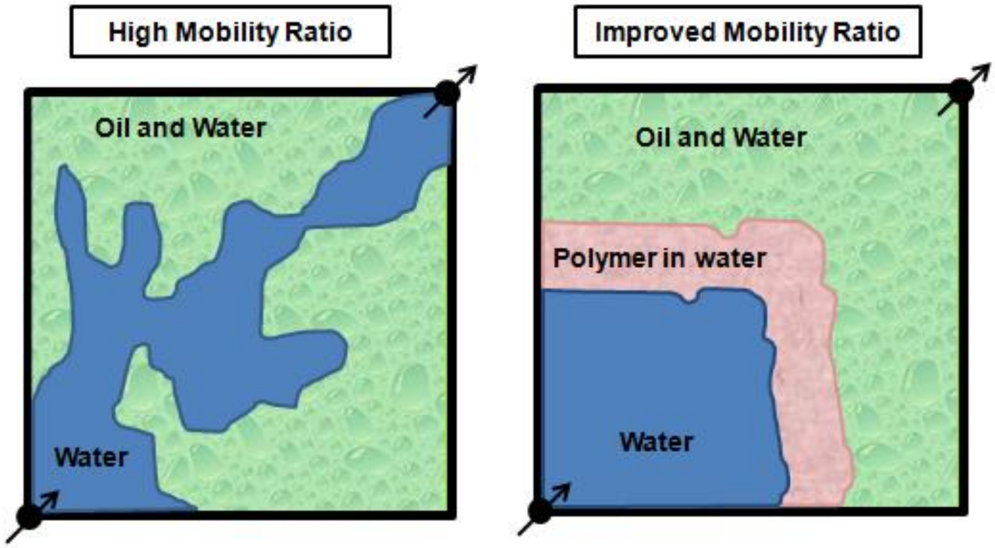


Figure 2 - 1. Example of viscous fingering due to unfavorable mobility ratio

The commercially attractive polymers for flooding can be classified into two classes; polyacrylamides and polysaccharides. Some common polymers that have been used extensively in the field are Xanthan gum, hydrolyzed polyacrylamide (HPAM), and copolymers of acrylic acid and acrylamide (Lake, 1996).

The primary goals of any polymer floods are primarily to increase water viscosity and to minimize the polymer loss due to adsorption (Clemens, et al., 2011). By reducing the high conductivity of the displacing fluid with polymer injection, injection fluid can be further distributed to the less-swept regions of the reservoir and thus the sweep efficiency of the waterflood can be improved. In designing a polymer flood, the drainage volume of the selected well clusters should be well understood in order to minimize water cut at the producing wells and maximize the total oil recovery (Teklu, et al., 2013).

However, the application of polymers in reservoirs with extreme permeability contrasts (i.e. fractured reservoirs) can be relatively limited. For reservoirs where extremely high permeability streaks or channels exist, improving a mobility ratio by polymer injection may not serve as an effective means to prevent low-recovery waterfloods. For such cases, conformance control to improve the areal and vertical sweep efficiencies is of great importance. Also, by crosslinking and gelling the polymer, its strength and stability can be improved and better controlled. These lead to the technologies of crosslinked polymer gels and microgels.

2.3. Polymer Gel and Microgel Technologies

In extent to the polymer technology, polymer gel and microgel technologies were developed primarily to increase the overall vertical and areal sweep efficiencies of the post-treatment waterfloods by in-depth fluid diversion. A relatively small amount of strong plugging agents or gels are injected to block high permeability zones, and thus improving the injection profile by diverting the water to other regions of the reservoirs to displace a portion of bypassed oil (Figure 2-2). The main objective of the gel treatment is to reduce the water production without significantly impacting the oil productivity.

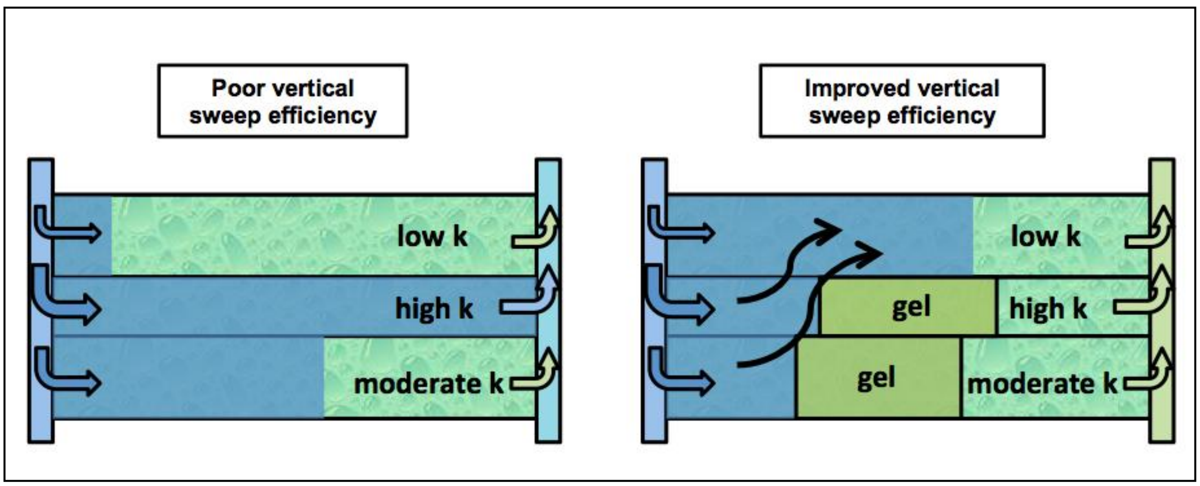


Figure 2 - 2. Example of early water breakthrough due to poor waterflood sweep efficiency

The primary distinction of polymer gel and microgel from polymer is the crosslinked structure. Gelling system consists of polymers and a crosslinker. Crosslinkers enable polymers to form a large network (gel network), which have superior ability in plugging pores than polymer alone does. The advantages of gels over polymers can be summarized as follows:

1) Due to the crosslinked structure, gels are more rigid or less penetrable than linear polymers. Their rheological behavior suggests that they are intermediate between linear polymers and hard spheres (Rousseau, et al., 2005).
2) Gels can be soft and deformable yet hold their shape like a solid. Their properties (i.e. strength, softness, stability) are controllable by manipulating the microstructure of polymers, crosslinkers, and surrounding liquids (Grillet, et al., 2012)
3) Gels can potentially achieve more significant, longer lasting, and more optimizable permeability reduction than polymers. The study indicated that with similar RF values designed, the crosslinked colloidal dispersion gel (or CDG) could result in a much higher RRF value when compared to the uncrosslinked polymer (Norman, et al., 1999).
4) Compared to polymers, gels can move more deeply into formations. The efficiency of gels in entering deep inside the porous media is related to their swelling and elastic deformation. For reservoirs with high degrees of crossflow, in-depth treatments are preferable to near-wellbore treatments.
5) The costs of gel treatments can be potentially cheaper than those of polymer treatments (Cuong, et al., 2011).
6) Gels can be removed after decreasing of excess water production (Cuong, et al., 2011).

A laboratory study of polymer gels for water shutoff in fractures conducted by Sydansk et al. (2004) revealed that water and oil usually ‘wormhole’ through the treatment gels that reside in fractures resulting in large residual resistance factors. However, the gel used in this study, chromium(III) carboxylate/acrylamide-polymer (CC/AP)), was characterized as total-shutoff or sealing agents as large permeability reduction was imparted to not only water but also oil flow. Therefore, this type of water shut-off would be beneficial only if the gels are selectively placed in the water-producing fractures. To improve the waterflood recovery via conformance control, it is more favorable for the injected polymers or gels to exhibit disproportionate permeability reduction (DPR) mechanism, which is the ability to reduce the permeability to water flow to a much greater extent than to oil or gas flow.

Some of the crosslinked gels used to control water production have been polyacrylamides-based polymers; e.g. polyacrylamide homopolymer (PAM), polyacrylamide tertiary butyl acrylate copolymer (PAtBA), or partially hydrolyzed polyacrylamides (PHPA), crosslinked with an inorganic crosslinker; e.g. chromium(III)carboxylate, or an organic crosslinker; e.g. polyethyleneimine (PEI). At high temperatures, a study has revealed that organically crosslinking might be preferred due to its covalent bonding. Inorganically crosslinked gels rely mainly on the ionic interaction between the positively charged trivalent cation (i.e. Cr^{3+}) and the negatively charged carboxylates which can be weakened greatly in high temperature environment (Al-Muntasheri, et al., 2009)

Fundamental gelling properties include gelling time, final gel strength, and depth of gel penetration. These properties usually depend on many factors such as shear stress (both in surface and near wellbore), physic-chemical environment of the formation including pH, salinity, temperature, etc. All of these properties and environmental factors are important in achieving a reliable gel simulation and, consequently, a successful gel treatment design. The operational aspects of a gel treatment than often need to be designed include zonal isolation, types of gel treatments, shut-in time, gel injection rate, and amount of gels to be injected.

Some of the most recent gel treatments or similar permeability-reducing materials that have been developed include:

- A new PPG enhanced surfactant-polymer system (Cui, et al., 2011)
- A novel polymer, which first was injected into fractures or fracture-like features as a millimeter-sized particle gel acting as a plugging agent, and then dissolved into polymer solution at a designated time due to reservoir's temperature (Bai, et al., 2013)

- A new profile control gel which can resist the alkali environment has also recently been developed to improve the ASP flooding in a strong alkali environment (Wang, et al., 2013).

Two characteristic factors often used to describe the recovery from chemical flooding and the DPR effect are Resistance Factor (RF) and Residual Resistance Factor (RRF):

1. Resistance Factor (RF) is the ratio of the injection brine mobility to the polymer mobility in the same reservoir rock:

$$RF = \frac{Mobility\ of\ Flooding\ Water}{Mobility\ of\ Polymer\ Solution} = \frac{\left(\frac{k_w}{\mu_w}\right)}{\left(\frac{k_p}{\mu_p}\right)} \qquad \text{.....……..(2-3)}$$

2. Residual Resistance Factor (RRF) is the ratio of the water flow resistance $\left(\frac{\mu_w}{k_w}\right)$ after the chemical injection to the water flow resistance before the chemical injection. It can be expressed in terms of water mobility $\left(\frac{k_w}{\mu_w}\right)$ as follows:

$$RRF = \frac{Initial\ Water\ Mobility\ before\ Chemical\ Injection}{Final\ Water\ Mobility\ after\ Chemical\ Injection} = \frac{\left(\frac{k_w}{\mu_w}\right)_{initial}}{\left(\frac{k_w}{\mu_w}\right)_{final}} \qquad \text{………..(2-4)}$$

These two characteristic factors can either be determined from laboratory core floods or empirical data in the field. In the current version of the numerical simulation used in this study (to be discussed in the next chapter), for PPG treatment, two explicit parameters are required as input parameters in calculating the RF. The two parameters are either obtained from the laboratory experiments or used as varied parameters for history matching.

As the focus of this study is on the preformed particle gel (PPG) which is classified as a type of microgels that is preformed prior to injection, it is worth looking at the distinct differences, first, between polymer gels and microgels, and second, between in-situ gels and preformed gels.

Polymer Gels (Bulk gels) and Microgels:

The primary difference between polymer gels and microgels is the concentration of reactants used in their respective formulations. Microgels are formed using relatively lower concentrations of polymer and crosslinker when compared to polymer or bulk gels. Therefore, they contain many separate polymer colloids instead of large branched polymers spanning the entire gels. As microgels are purposely designed for water shutoff treatment, they reduce the permeability disproportionately by forming thick absorbed layers that are soft enough to not affect the oil permeability while decreasing the water permeability (Chauveteau, et al., 2004). In addition, unlike polymer-based system, when injected into a multilayered reservoir, microgels invade the low-permeability zones significantly less due to the low viscosity of their solutions and Steric effects (Cozic, et al., 2009).

Chauveteau et al. have summarized characteristics that have an impact on the performances of microgels as follows (Chauveteau, et al., 2004):

1) *Mean size and distribution* – determine the capability of microgels in reducing water permeability and the quality of its self-placement between different layers in the absence of zonal isolation (bullhead treatment).
2) *Internal deformability or softness* – to be a good DPR product, microgels must be deformable enough to be collapsed onto the pore surface when they are subjected to the capillary force. The softness of microgels is proportional to effective crosslink density. It is usually quantified by an internal elastic modulus.
3) *Interaction properties* – either between microgels and rock surface or between microgels themselves. The attractive interaction between the microgels and the rock surface affects the adsorption of the particles while the attractive or repulsive

interaction between the microgels themselves induces either a multilayer or monolayer gel formation on the rock surface. In some cases, multilayer of gel formation could lead to plugging the porous media.

4) *Long term stability under reservoir conditions* – depends on the purity of the chemical species used during the production process and their crosslink density.
5) *Non-toxicity* – this is as per environmental protection requirement.

In summary, microgels can provide a number of advantages over polymer or bulk gels; namely, better injectivity, deeper gel penetration, higher residual resistance permeability in high permeability channels, and the ability to selectively penetrate the highest permeability layers when properly designed.

To date, there are different types of microgels developed; for example, preformed particle gel or PPG, colloidal dispersion gel or CDG, pH-sensitive microgels, temperature sensitive microgels, microgels for relative permeability modification (RPM), and nano-sized gels.

In-situ Gel and Preformed Gels:

With in-situ gel treatments, the mixture of polymer and crosslinker called gelant is injected into the formation and react to form gel at reservoir conditions. This allows some major drawbacks such as inability to control gelation time, gelling uncertainty due to shear degradation, and change of gelant compositions and dilution by formation water. By mixing the polymer and the gelant on the surface, the preformed gel treatment, therefore, overcome these disadvantages as it allow more control of gelation time and gel strength to be achieved prior to injection.

A flow experiment of gelled-polymer in a long conduit conducted by Stan et al. in 2009 (McCool, et al., 2009) suggested that flow of preformed gel was characterized by high flow resistance in the entrance section while flow of in-situ gel was characterized by increasing in flow resistance as gelation occurs, followed by flow at steady resistant value.

2.4. Preformed Particle Gel (PPG)

Preformed Particle Gel, or PPG, is a new type of temperature-resistant and salt-tolerant pre-crosslinked swellable particle gel which is specifically developed for oilfield application of enhancing oil recovery by conformance control. It is an improved super absorbent polymer (SAP) consisting of dried, cross-linked, polyacrylamide powder (Bai, et al., 2013). SAPs are a unique group of materials that can absorb over a hundred times their weight in liquids and do not release the absorbed fluids easily under pressure. They are primarily used as absorbent aqueous solutions for diapers, feminine hygiene products and agriculture industry. However, due to their fast swelling time, low strength and instability at high temperature, the traditional SAPs in the markets do not meet the requirements for conformance control. A series of new SAPs called preformed particle gels (PPG) was developed later to suit the utilization of enhanced oil recovery via reservoir conformance control. According to Coste et al. (Coste, et al., 2000), PPG can contribute to the increase in oil recovery by two mechanisms:

1) Inducing a resistance to the water flow in the high permeability layer and diverting the flow to the low permeability layer
2) Pushing the oil remained out of the pore space by entering the pore bodies

Synthesis and Fabrication of PPG

Bai et al. described the synthesis and fabrication of PPG in a number of papers (Bai, et al., 2004 and 2007). The procedure started with synthesizing bulk gel from an acrylamide monomer, a crosslinker, an initiative, and additives at room temperature. Then, the bulk gel was cut into small pieces with a cutting machine and dried at a high temperature to form xerogel particles. Finally, the dried particles were ground and sieved to meet the requirement of specified treatments. Shown in Figure 2-3 is a schematic of PPG synthesis and fabrication process.

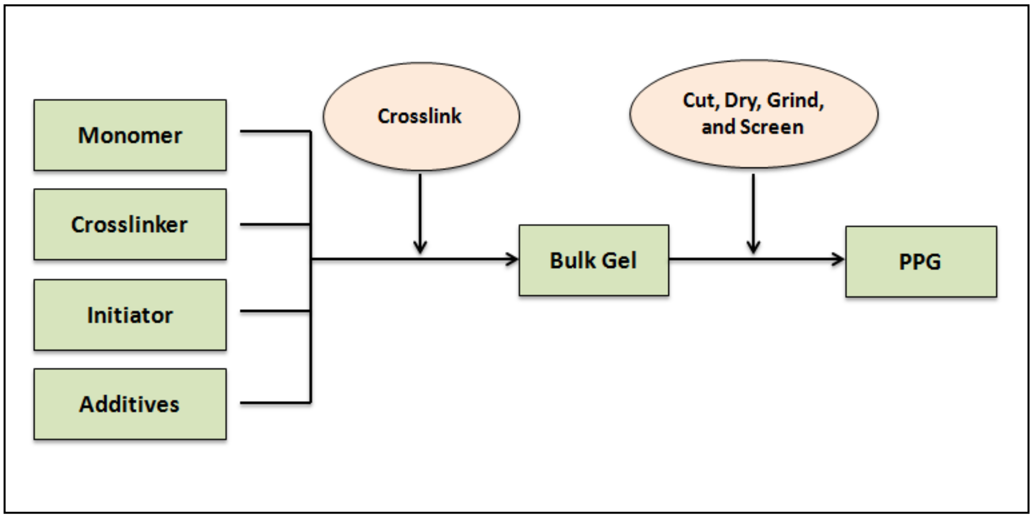


Figure 2 - 3. A schematic of PPG synthesis and fabrication process (Bai, et al., 2007)

Figure 2-4 illustrates how dried PPG particles swell after contacting water. The swelling particles are elastic and deformable, thus, can be injected into reservoirs to fully or partially control the fluids flow in high permeability, fractures, or fracture-like channels.

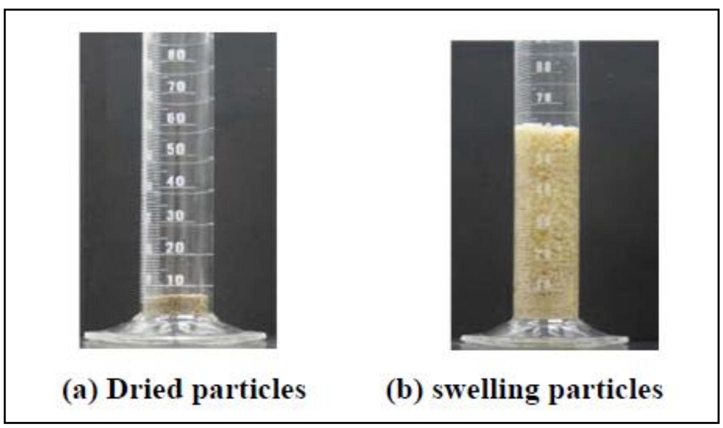


Figure 2 - 4. Dried and swelling PPG particles (Bai, et al., 2014)

The swelling capacity of PPG (A) is defined as follows:

$$A = \frac{M_l - M_s}{M_s} \qquad \text{……...…………………..(2-5)}$$

where M_l is the volume after swelling and M_s is the volume of the dry gel before swelling.

Propagation Mechanisms of PPG

Based on the experimental studies on behavior and characteristics of particle gel transporting through porous media, PPG can be treated as one additional component in the aqueous phase and the simplified treatment can be characterized upon the following physical considerations (Bai, et al., 2004; 2007):

1. **Flow Pattern:** PPG particle can transport through a porous media in six behavior patterns

   1.1) ***Direct Pass:*** when a particle is smaller than a pore throat, it can move straight through a pore throat once displaced by water.

   1.2) ***Adsorption:*** when a particle is so small that the attraction force between rock and particle surface is dominant, it will be adsorbed or retained onto a rock surface.

   1.3) ***Trap:*** a particle is blocked at the entrance of a pore throat and cannot move forward.

   1.4) ***Deform and Pass:*** due to the displacement force applied by flowing water, a particle changes its shape and passes through a throat. It is possible that the deformed particle may revert to its original shape after entering a larger pore.

   1.5) ***Shrink and Pass:*** due to the displacement force applied by flowing water, some water is squeezed from a swollen particle reducing the particle size so the particle is able to pass through the pore throat. It is possible that the shrunken particle may reabsorb some water from the pore space and revert to its original size.

   1.6) ***Snap-off and Pass:*** a particle is broken into smaller particles by a pore throat, and the smaller particles continue to pass through pore throats.

   The last four patterns happen when a particle size is larger than a pore-throat size. In reality, several patterns occur concurrently when PPG suspension is injected into a porous media. The dominant pattern depends primarily on the diameter ratio of the swollen PPG particle and the pore throat, the strength of the swollen PPG particle, and the fluid driving force.

2. **Threshold Pressure Gradient for Elastic Particle Flow:** unlike other traditional particles, swollen PPG particles are deformable, and they can pass through the pore throats smaller than particles themselves. However, the particle movement requires a threshold pressure gradient, i.e., the minimum pressure gradient to force the particles to move through a porous medium. The threshold pressure gradient depends mainly on the ratio of particle diameters to average pore size and the strength of gel particle. At the same ratio of particle to pore throat size, hard particle has higher threshold pressure gradient than soft particles.

3. **Particle Retention in Porous Media:** the particles are not completely carried by the water flow as part of them will retain in the porous media due to gravitational deposition, adsorption, or interaction with pore surfaces. The retention density increases with the particle concentration and the hard particles have a higher retention than the soft ones as it is harder for them to move through pores and pore throats.

Properties of PPG

To date, a series of PPG has been developed for the purpose of conformance control. Bai et al. reported several extensive reviews of PPGs for conformance control that covered from PPGs mechanisms to field applications. Briefly summarized below are the typical features of PPG (Bai, et al. 2004, 2007, 2008, and 2013):

1. Size: adjustable from µm to cm (after swelling). It is recommended that PPG be sized to neither penetrate into nor form a cake on the surface of the low-permeability rocks. According to the experiments by Elsharafi (Elsharafi, et al., 2013), swollen particles cannot propagate through the porous media when the ratio of particle size to pore throat size is higher than 17.
2. Swelling ratio in formation water: 30 to 200. PPG's swelling ratio can be correlated with the water salinity or brine concentration (Bai, et al., 2007).
3. Salt resistance: all kinds of formation salts and concentrations acceptable
4. Thermal stability: in excess of 1 year below 110 °C

5. Strength: adjustable with high strength product available as strong gels were preferable to weak gels when formation damage is concerned.

Intrinsic properties of PPG are controlled by its synthesizing composition and its surrounding environment conditions, e.g. temperature, salinity, etc. High salinity results in a smaller swelling ratio. Increasing the temperature also results in swelling ratio increases.

Advantages and Disadvantages of PPG

The advantages of PPG for conformance control were inclusively studied by Coste et al. (2000), Bai et al. (2004, 2007, 2008, and 2013), Wu et al. (2008), Zhang, et al. (2010), and Elsharafi, et al. (2013). A summary of their work follows:

1. Compared to traditional SAPs, PPG can be synthesized to have higher strength and stability with controllable swelling time. That is both strength and size of PPG can be tailored to suit variety of oilfield applications. In other words, the damage or penetration caused by PPG on low-permeability, oil-rich zones could be effectively controlled by adjusting particle gel strength, particle size, and brine concentration. It was demonstrated that millimeter-sized PPG would not propagate through the formation zone with rock permeability less than a 300 mD approximately.

2. As PPG is synthesized prior to contacting a formation, it overcomes many drawbacks inherent in in-situ gelation systems; for examples, uncontrolled gelation times, variations in gelation due to shear degradation, and gelant compositional changes induced by contact with formation minerals and fluids.

3. Compared to other types of microgels and polymers, PPG is considered highly insensitive to hydrocarbon reservoir environments. It can be manufactured to resist the temperature as high as 120°C (250°F) and compatible with any kind of formation water.

4. In contrast to other traditional gels which are usually sensitive to salinity, multivalent cations, and H_2S in the produced water, PPG is highly insensitive to those physicochemical properties. PPG suspension can be prepared using produced water, which is environmental friendly and beneficial in terms of freshwater saving.

5. PPG treatment cost can be very attractive. The cost of material is approximately $2 US/lb (Bai, et al., 2009). The operation and surface facilities for PPG injection are simple and straightforward. Generally, there is usually only one additional component during PPG treatment, which is the mixing tank for PPG. Therefore, the operating cost for PPG treatment is minimal.

Nevertheless, it is not recommended to inject PPG in conventional porous media with low permeability. The injectivity of PPG is still questionable as its size is usually much larger than the conventional rock pore throats. Unlike the nano-sized particle gel, for instance, the BrightWater® (Pritchett, et al., 2003; Frampton, et al., 2004), PPG can only be used to control conformance for the reservoirs with small fractures or high permeability channels. In addition, for the reservoirs with severe open channels or super-high-permeability open fractures, there is still a possibility that PPG will be flushed out from producers. In some cases, injecting bulk gels or CDG could be considered as preferred options.

Field Applications of PPG

Among other types of microgels, PPG is considered more dedicated to treatments of fractures or very high permeability streaks. PPG can preferentially enter into fractures or fractured-like channels while minimizing its penetration into low permeable hydrocarbon zone. With the appropriate size and properties, PPG should be designed to transport through high permeability conduits and not penetrate into conventional permeability mediums. The minimized gel penetration in low permeable areas can result in significant reductions in the required gel volumes because fracture or fractured-like channels usually comprise less than 10% of the reservoir volume (Bai, et al., 2008) and, more importantly, cause less damage on the overall productive oil zones.

Since 1999, PPG or PPG combined with in-situ gels have been used to treat more than 4000 wells in mature oil fields by China (Bai, et al., 2013), Halliburton (Bai, et al., 2009), Occidental oil company (Pyziak, et al., 2007), and Kinder-Morgan (Larkin, et al., 2008). Although its mechanisms to control performance and its applied conditions were sometimes unclear, PPG has been applied for conformance control in mature oil fields in China, and most applications have been shown positive results (Liu, et al., 2006)

To date, the characteristics of reservoirs where PPG treatments have successfully been employed have been compiled (Bai, et al., 2013; Qiu, et al., 2014) as follows:

- Reservoirs with natural fractures
- Reservoirs without natural or hydraulic fractures
- Reservoirs with CO_2 flooding
- Reservoirs with polymer flooding
- Reservoirs with temperature: 30-110 °C
- Reservoirs with formation water salinity: 2,900 - 300,000 ppm

Some applications of PPG conformance control so far have been in high-salinity, high-temperature reservoirs, low-salinity, low-temperature reservoirs, reservoirs with sand production, applications in polymer flooding areas, applications in remediating large channels, fractures, and void conduit, applications in remediating unwanted communication in a CO_2 flooding reservoir, etc. The study of PPG treatments in 655 injection wells in China (Qiu, et al., 2014) revealed that there were no injection problems even in reservoirs without fractures and that even though not all applications had significant incremental oil produced, no negative effects were found from PPG injection.

PPG was also used in combined with polymer and surfactant in a chemical flooding system, Heterogeneous Combination Flooding System (HCFS) (Cui, et al., 2011), where PPG can not only migrate and penetrate in porous medium, but also generate more significant volumetric sweep efficiency by the cycle of piling up-plug-pressure rising-extending and deforming to pass through porous throats than the conventional polymer flooding to modify the existing dominant migration path.

Chapter 3: Numerical Model Description: UTGEL

UTGEL (Delshad, et al, 2011) is a finite difference three-dimensional multiphase multi-component chemical composition reservoir simulator. It is developed at the Center for Petroleum and Geosystems Engineering of The University of Texas at Austin for the particular purpose of modeling chemical EOR processes of conformance controlling using different types of gels. The simulator comprises comprehensive modules established for gel rheological and transport properties such as shear thinning viscosity, adsorption, permeability reduction, and inaccessible pore volume. It consists largely of mass balance calculation and gel transport model. It is used to simulate a wide range of displacement processes in both laboratory and field scales.

3.1. Mass Balance and Flow Calculation

As each gridblock can possess different permeability and porosity, heterogeneity and variation in relative permeability and capillary pressure are allowed throughout the porous media. There are three fundamental equations used in this model for mass balance and flow calculation:

1. **The mass balance equation for each species**

   The mass conservation equation for each component is expressed by overall volume per unit pore volume as

$$\frac{\partial}{\partial t}\left(\phi \tilde{C}_K \rho_K\right) + \vec{\nabla}.\left[\sum_{l=1}^{n_p} \rho_K \left(C_{Kl}\vec{u}_l - \vec{\vec{D}}_{Kl}\right)\right] = R_K \quad \text{(3-1)}$$

where

$\tilde{C}_K$ is the overall volumetric concentration of component K,

ρ_K is the density of pure component K,

n_p is the number of components,

C_{Kl} is the concentration of component K in phase l,

$\vec{u}_l$ is the volumetric flux of phase l,

$\vec{\vec{D}}_{KL}$ is the dispersive flux of component K,

and R_K is the injection or production rate for component K per bulk volume K.

The overall volumetric concentration of component K (or $\tilde{C}_K$) can be computed as follows:

$$\tilde{C}_K = \sum_{l=1}^{n_p} S_l C_{Kl} + \hat{C}_K \text{, for } K = 1,2,\dots,n_p$$

...…………………….....(3-2)

where

S_l is the saturation of phase l, and $\hat{C}_K$ is the adsorbed concentration of component K.

2. The energy balance equation

The energy balance equation is derive by assuming that energy is a function of temperature only and energy flux in the reservoirs occurs by advection and heat conduction only.

$$\frac{\partial}{\partial t}\left[(1-\phi)\rho_s C_{vs} + \phi \sum_{l=1}^{n_p} \rho_l S_l C_{vl}\right] T + \vec{\nabla}.\left(\sum_{l=1}^{n_p} \rho_l C_{pl}\, u_l T - \lambda_T \vec{\nabla}\, \mathrm{T}\right) = q_H - Q_L$$

……...………...………..(3-3)

where

T is the reservoir temperature,

C_{vs} and C_{vl} are the rock and phase l heat capacities at constant volume,

$C_{pl}$is the phase l heat capacity at constant pressure,

λ_T is the thermal conductivity (assumed constant),

q_H is the enthalpy source term per bulk volume,

and Q_L is the heat loss to formations

3. The pressure equation

The pressure equation is developed by summing the mass balance equations, substituting Darcy's law for the phase flux terms, using the definition of capillary pressure, and noting that, for each phase, the summation of the volume concentration of all components is equal to one.

$$\phi C_t \frac{\partial P}{\partial t} - \vec{\nabla}.\vec{\vec{\mathrm{k}}}.\lambda_{rTc}\vec{\nabla}\mathrm{P}_1 = -\vec{\nabla}.\sum_{l=1}^{n_p}\vec{\vec{\mathrm{k}}}.\lambda_{rlc}\vec{\nabla}\,\mathrm{h} + \vec{\nabla}.\sum_{l=1}^{n_p}\vec{\vec{\mathrm{k}}}.\lambda_{rlc}\vec{\nabla}\,\mathrm{P}_{\mathrm{cl1}} + \sum_{\mathrm{K}=1}^{\mathrm{n_{cv}}}\mathrm{Q_K}$$

…………..………………..(3-4)

where

$\lambda_{rlc} = \frac{k_{rl}}{\mu_l}\sum_{K=1}^{n_{cv}}\rho_K C_{Kl}$ and total relative mobility with the correction for fluid compressibility is $\lambda_{rTc} = \sum_{l=1}^{n_p}\lambda_{rlc}$,

C_t is the total compressibility which is the sum of the rock (C_r) and volume-weighted component (C_K^o) compressibilities :

$$C_t = C_r + \sum_{K=1}^{n_{cv}} C_K^o \tilde{C}_K$$ …………..………………..(3-5)

Treating gel particle as a solute in the aqueous phase, the mass balance equations are solved for water, oil, total divalent cation, and gel species. An overall mass balance of water and oil obtains the pressure of each fluid phase. And finally, the energy balance equation is used to determine the temperature. The number of components is variable depending on the application.

The assumptions for developing flow equations were summarized by Goudarzi (Goudarzi, et al., 2013) as follows:

1. Slightly compressible rock and fluid (no gas involved in the calculation)
2. Darcy's law applied
3. Ideal mixing
4. Fickian dispersion with full tensor dispersion coefficient
5. No flow and no dispersive flux across the impermeable boundaries

3.2. Gel Transport Model

The transport ability of PPG through porous media is a function of many parameters including pore diameter, structure of PPG, its synthetic size, and salinity. There are two important properties for modeling PPG flow through porous media. They are permeability reduction factor and viscosity. As for the adsorption concentration of PPG, a Langmuir-type isotherm is used to describe the adsorption level of PPG, same as that of surfactant and polymer.

1. Permeability Reduction Factor

Permeability reduction factor is one of the most important parameters in modeling gelant flow in porous media. The effect of gel on aqueous-phase permeability reduction is taken into account through a residual resistance factor which is used for polymer flooding (see Equation 2-4).

PPG particles are able to pass through the pores with specific conditions depending on the pore diameter, the structure of particles, and the particle size. The size of PPG particle changes with salinity as PPG swelling ratio is a function of salinity and PPG particles are defined as weak or strong particles by salinity.

First, the swelling ratio and then swelled particle size are calculated after solving the pressure and concentration equations. Then, whether PPG particle is able to pass through the grid block containing the particle is determined by (a) the size of the particle and (b) the pore throat diameter of the grid block.

(a) Swelling ratio or expansion ratio is the volume ratio of before and after the expansion of PPG particles. Bai et al. (Bai, et al., 2007) reported a relationship for swelling ratio as a function of salinity. They showed that the particles swell very fast within 60 minutes and the final swelling ratio is inversely proportional to salt concentration. Higher salt concentration results in smaller swelling ratio. The equation for swelling ratio is presented as follows:

$$SF = a_p(C_{SEP})^{n_p} \qquad \text{.........................(3-6)}$$

where a_p and n_p are required input parameters in the software (corresponding to APPGS and PPGNS in INPUT files, respectively); SF is swelling ratio, and C_{SEP} is effective salinity in meq per liter which takes into account the combined effect of anions and divalent cations. According to a laboratory test conducted by Bai in 2007 (Bai, et al., 2007), PPG particles move towards becoming strong particles as salt concentration increases. As the final swelling ratio is inversely proportional to salt concentration, n_p appears negative.

(b) The average pore throat diameter is calculated using porosity and permeability of each grid block as the pore throat radius (r_h) can be estimated by

$$r_h = 1.15\sqrt{\frac{8\,\bar{k}}{\phi}} \qquad \text{.........................(3-7)}$$

where the appropriate average permeability k is given by

$$\bar{k} = \left[\frac{1}{k_x}\left(\frac{u_{x1}}{u_1}\right)^2 + \frac{1}{k_y}\left(\frac{u_{y1}}{u_1}\right)^2 + \frac{1}{k_z}\left(\frac{u_{z1}}{u_1}\right)^2\right]^{-1}$$

..............................(3-8)

The conditions for passing PPG particle through the pore throats are set to be different for weak and strong PPG particles:

- For weak PPG particles; If PPG diameter is less than 5.7 of pore throat diameter
- For strong PPG particles; If PPG diameter is less than 1.3 of pore throat diameter

If PPG can pass through the grid block, the permeability reduction factor is then calculated and the grid block permeability is modified. The degree of permeability reduction depends on many factors, namely; gel type, molecular weight, shear effects, and rock properties. To date, the general equation for permeability reduction factor of PPG in UTGEL is based on Zhang et al.'s experiment (Zhang, et al., 2010) as follows:

$$R_{kfp} = a_{kp} q^{n_{kp}} \qquad \text{.....................................(3-9)}$$

where R_{kfp} is the permeability reduction factor, a_{kp} and n_{kp} are the required input parameters in the software (corresponding to APPGFR and PPGNFR parameters in INPUT files, respectively), and q is the flow rate in ft^3/day.

To ensure that permeability reduction remains during the post-waterflood injection, the residual permeability reduction is defined as follows:

$$RRF = R_{kfp,factor} R_{kfp,max} \qquad \text{..................................(3-10)}$$

where $R_{kfp,factor}$ is a model parameter and $R_{kfp,max}$ is the maximum permeability reduction.

2. Viscosity

The viscosity of PPG suspension is a function of gel concentration, water viscosity, and shear rate. At low shear rate, the viscosity for small microgel concentration below 2000 ppm is calculated using the Huggins equation (Shi, et al., 2011)

$$\mu_M = \mu_s \left(1 + [\eta] C_M + K_H [\eta]^2 {C_M}^2\right) \qquad \text{................................(3-11)}$$

where μ_M is the effective viscosity of microgel solution at low shear rate, μ_s is the solvent viscosity (usually is water), $[\eta]$ is the zero-shear intrinsic viscosity, which characterizes the internal density of the microgel colloids, K_H is the Huggins constant, which characterizes the interactions of the microgel colloids in solution, and C_M is the microgel concentration, which is defined as the amount of microgel per unit volume of solution and usually expressed in terms of mass per unit volume. The equation is re-written in terms of PPG model parameters as follows:

$$\mu_M = \mu_s\left[1 + A_{PPG,1}C_{PPG} + A_{PPG,2}C_{PPG}^2\right] \quad \text{……………..(3-12)}$$

where $A_{PPG,1}$ and $A_{PPG,2}$ are model input parameters, and C_{PPG} is the PPG concentration in aqueous phase.

As the viscosity of gel decreases with increasing shear rate, the effective gel viscosity can be modified using Meter's equation (Meter, et al., 1964) as follows:

$$\mu_M = \mu_s + \frac{\mu_M^0 - \mu_s}{1+\left(\frac{\dot{\gamma}_{eq}}{\dot{\gamma}_{1/2}}\right)^{P_\alpha - 1}} \quad \text{……..…………..(3-13)}$$

and

$$\dot{\gamma}_{eq} = \frac{\dot{\gamma}_c|\mu_\iota|}{\sqrt{\bar{k}k_{r\iota}\phi S_\iota}} \quad \text{……..…………..(3-14)}$$

where

μ_M^0 is the microgel solution viscosity at zero shear rate,

$\dot{\gamma}_{eq}$ is the equivalent shear rate,

$\dot{\gamma}_{1/2}$ and P_α are model input parameters,

$\dot{\gamma}_c$ is the shear rate correction,

$|\mu_\iota|$ is the magnitude of flux for phase l,

$k_{r\iota}$ and S_ι are the relative permeability and saturation of phase l respectively, and the appropriate average permeability $\bar{k}$ is, again, given by

$$\bar{k} = \left[\frac{1}{k_x}\left(\frac{u_{x1}}{u_1}\right)^2 + \frac{1}{k_y}\left(\frac{u_{y1}}{u_1}\right)^2 + \frac{1}{k_z}\left(\frac{u_{z1}}{u_1}\right)^2\right]^{-1} \quad \text{……………..(3-15)}$$

Chapter 4: PPG Experiment History Matching

In this chapter, the results of modeling and simulations of several experiments conducted at Missouri University of Science and Technology are presented. Five different experiments were successfully modeled and history matched with UTGEL conformance control reservoir simulator (December 2013 version):

- CASE I: Water flow in an open fracture model
- CASE II: Two-phase flow sandpack
- CASE III: Two-phase flow coreflood
- CASE IV: Two-phase flow sandpack with different PPG injection rates
- CASE V: Two-phase flow using parallel sandpack

Note that the history matches of CASE I and II using UTGEL had previously been implemented and presented (Goudarzi, et al., 2013). However, with the further developed version of UTGEL released in 2013, history matches of both cases were re-performed in this study.

4.1. CASE I: Water Flow in an Open Fracture Model

Objectives: Zhang et al. (2010) performed an experiment by constructing a transparent fracture model to visually track swollen PPG propagation through open fractures and water (brine) flow through PPG placed in fractures. Three factors; namely, injection rate, fracture width, and brine concentration, were investigated to understand how they impact PPG injection pressure.

Materials and Experiment Setup: Figure 4-1 illustrates the flow chart of the experiment setup composed of two syringe pumps (one for PPG injection and the other for brine injection), one accumulator, and one fracture model. The fracture model was made of two acrylic plates with an O-ring rubber in between. The fracture width was controllable using bolts, nuts, and shims that held the two plates together. The acrylic plates were transparent so that the gel and brine movement could be clearly observed (see Figure 4-2). There were inlet and outlet holds at each ends of the model for injecting and discharging the PPG and brine solution. Pressure transducers were connected at the inlet to record the injection pressure.

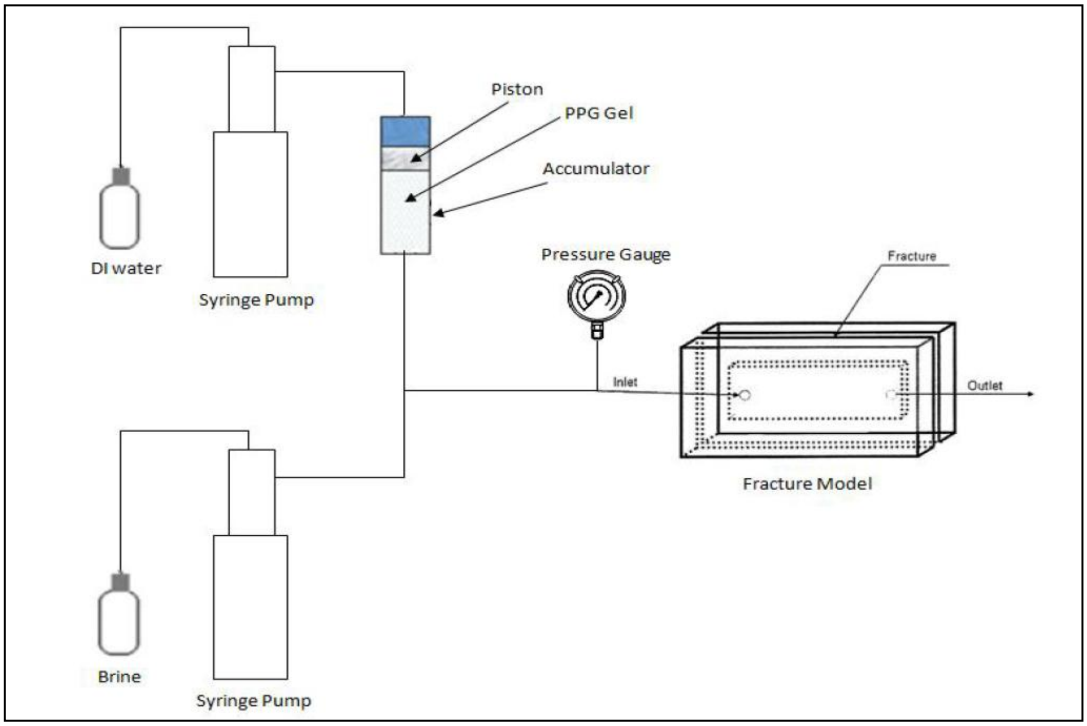


Figure 4 - 1. Open fracture experiment setup (Zhang, et al., 2010)

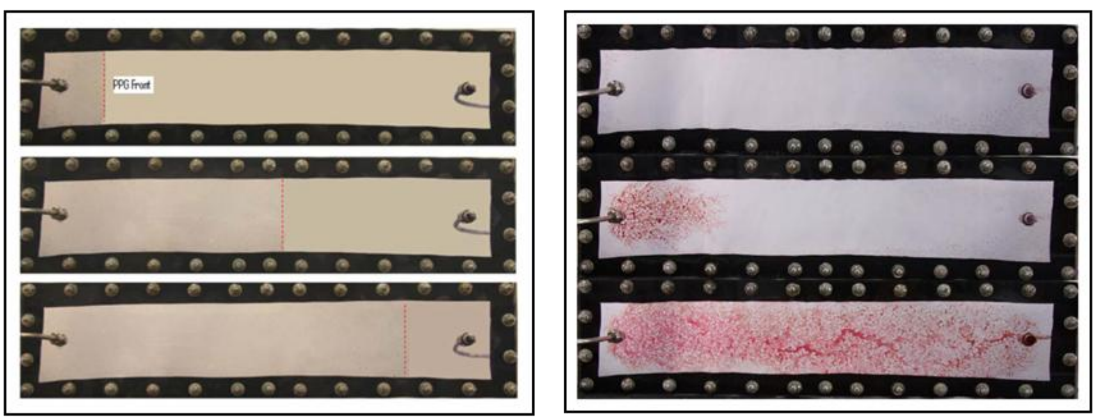


Figure 4 - 2. left - PPG movement during gel injection into a fracture model,

right - Brine movement during brine injection into a gel packed fracture model (Zhang, et al., 2010)

Experimental Procedure: The experiments were conducted by first injecting brine into the fracture model. Then PPG suspension was dispensed into the fracture model through an accumulator. After the gel was in place, brine was injected once more into the gel packed fracture to investigate the plugging efficiency of gel on water. For all three injection steps, the injection pressure was recorded while the propagation of fluids was being monitored. Six injection rates, three fracture widths, and four brine concentrations were used in these experiments. With only one parameter adjusted at a time to examine the impact and to rank the influence of each factor (i.e. injection rate, fracture width, and brine concentration), the total number of experiments was 72.

Numerical Simulation: Using the data obtained from the experiment, we constructed a simple 1-D numerical model (Figure 4-3) and performed a series of simulations to model PPG propagation and its effect on permeability reduction. Note that the original permeability of the fracture was calculated from its width using the conventional Cubic law (Klimczak, et al., 2010)

$$k = \frac{w^2}{12} \qquad \text{…………………………..(4-1)}$$

With most parameters known, there were only two input parameters that needed to be adjusted in the simulation to match the pressure response for each experiment. The two parameters were the viscosity parameters, $A_{PPG,1}$ and $A_{PPG,2}$ (see Equation 3-12, Chapter 3). Once the history matches of all experiments were completed, a feasible range for each viscosity parameter was then compiled as recommendations for future PPG simulation. Key input parameters are given in Table 4-1. Complete input data of this simulation run can be found in Appendix A-1.

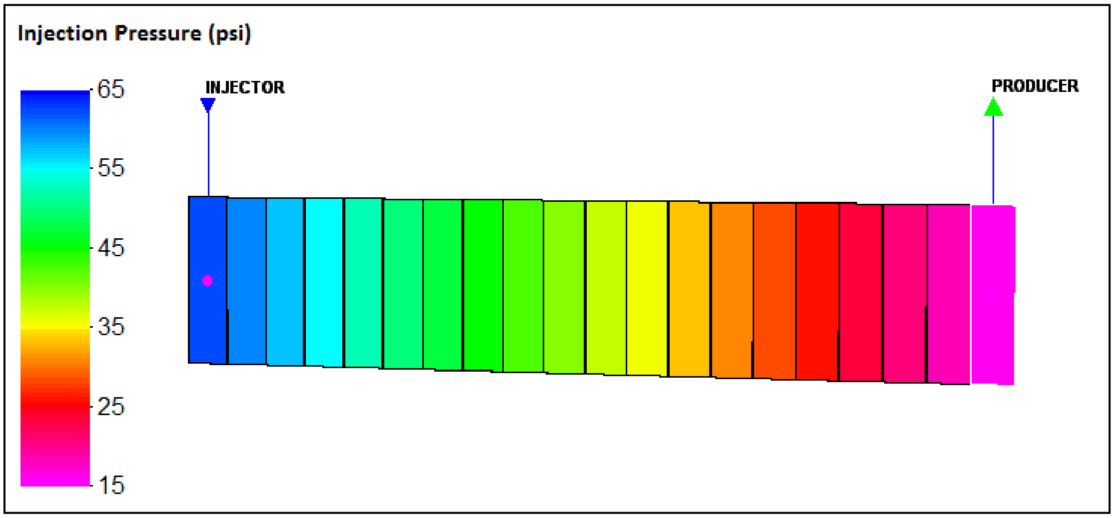


Figure 4 - 3. Simulation grids for the open fracture experiment

Table 4 - 1. UTGEL simulation input parameters for the open fracture experiment

Model	1-Dimentional Cartesian
Number of gridblocks	20 x 1 x 1
Δx, Δz	2.75, 1 cm
Δy (fracture width)	0.5, 1, 1.5 mm
Porosity	1.0
Permeability (calculated from fracture width)	20,833; 83,333; 187,500 Darcy
Initial water saturation (single phase flow)	1.0
Water viscosity	1.0 cp
Temperature	72.5 °F
Outlet pressure	14.7 psi
Salinity	0.05, 0.25, 1, 10 wt%
Injection / production rate	5, 10, 15, 20, 25, 30 ml/min
Injection / production period	5 PV
PPG concentration	400 ppm
PPG diameter	585 µm

Simulation Results:

1. The 0.5-mm fracture width model experiments

Figure 4-4 shows the comparisons of the injection pressures measured in the experiments and the injection pressures obtained as results of the simulation history matching at different injection rates and brine concentrations for the specific fracture width of 0.5 mm. It can be observed that the injection pressure increased with an increase in either injection flow rate or brine concentration, and that the simulation results matched the measured data reasonably well.

The pressure values obtained from both approaches and the calculated errors of the simulation with respect to the measured values are summarized in Table 4-2. The high percentages of error were mostly those of the low flow rate experiments. However, all errors from the history matching were well below 10%.

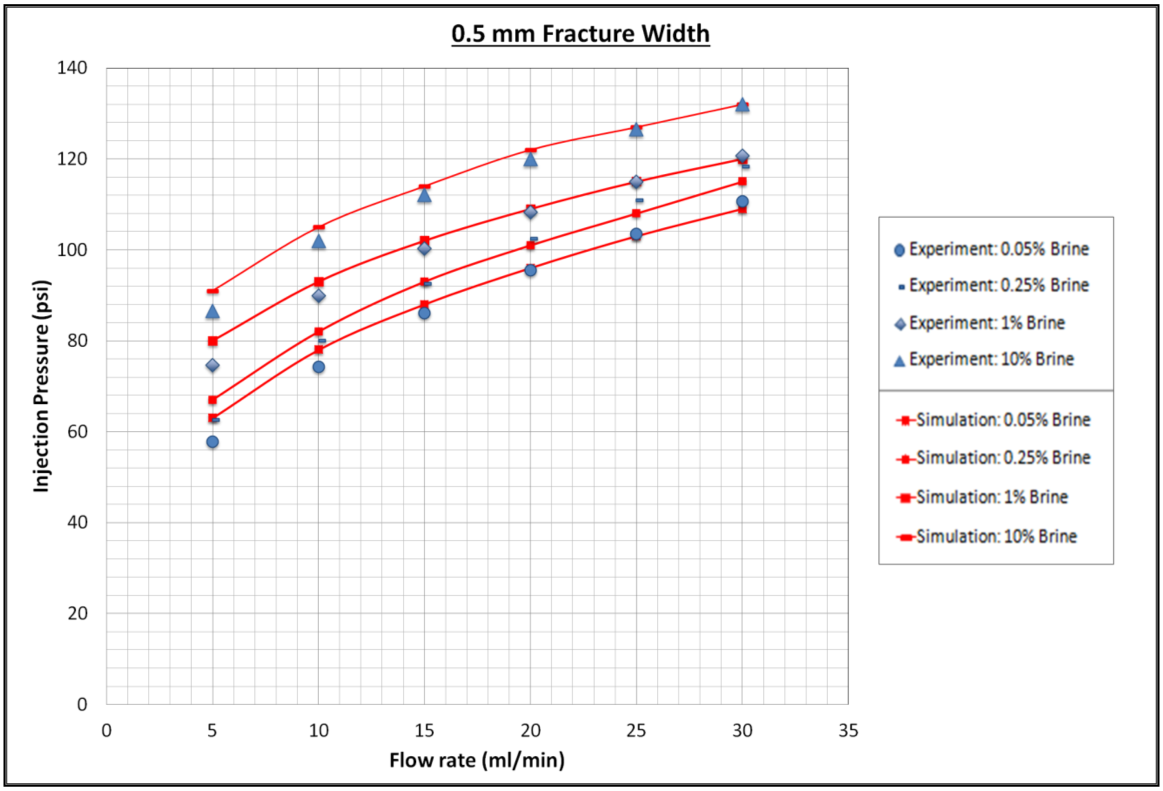


Figure 4 - 4. Injection pressure vs. flow rate, 0.5-mm fracture width model

Table 4 - 2. History match results for the 0.5-mm fracture width model

Flow rate (ml/min)	Pressure (psi)											
	0.05% Brine			0.25% Brine			1% Brine			10% Brine		
	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error
5	58	63	9%	63	67	7%	75	80	7%	86	91	5%
10	74	78	5%	80	82	2%	90	93	3%	102	105	3%
15	86	88	2%	92	93	1%	100	102	2%	112	114	2%
20	95	96	1%	102	101	1%	108	109	1%	120	122	2%
25	104	103	0%	111	108	3%	115	115	0%	126	127	0%
30	111	109	1%	118	115	3%	121	120	1%	132	132	0%

2. The 1.0-mm fracture width model experiments

Figure 4-5 shows the comparisons of the measured and history matched injection pressures obtained at different injection rates and brine concentrations for a fracture width of 1.0 mm. Similar to the 0.5-mm fracture width model experiments, the injection pressure increased with the increase of both injection flow rate and brine concentration. Also, the simulation results matched the measured data reasonably well. However, it can be observed that, at the same flow rate and brine concentration, the injection pressure of the 1.0-mm fracture width model experiment was lower than that of the 0.5-mm fracture width model experiment.

The pressure values obtained from both approaches and the calculated errors of the simulation with respect to the experimental values for the 1.0-mm fracture width model experiments are summarized in Table 4-3. All errors from the history matching were well below 10% except that of the 0.05% brine and 5 ml/min flow rate experiment where the injection pressure was relatively low.

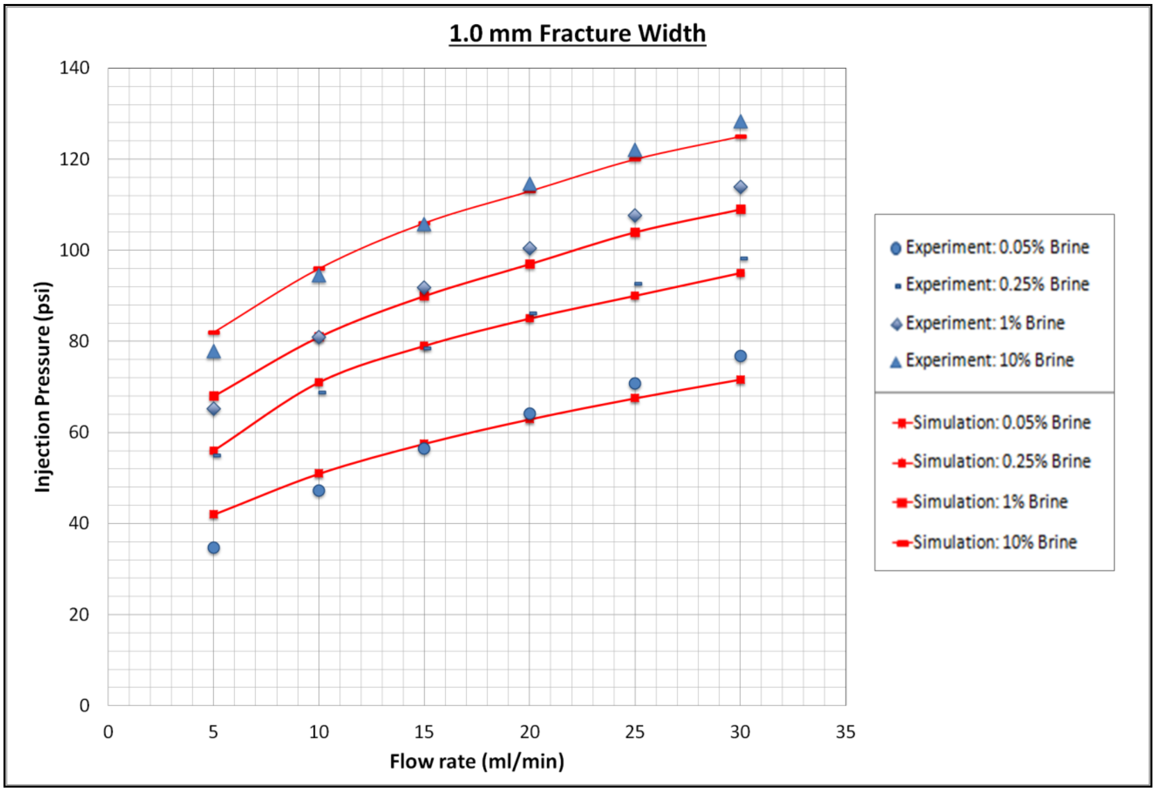


Figure 4 - 5. Injection pressure vs. flow rate, 1.0-mm fracture width model

Table 4 - 3. History match results for the 1.0-mm fracture width model

Flow rate (ml/min)	Pressure (psi)											
	0.05% Brine			0.25% Brine			1% Brine			10% Brine		
	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error
5	35	42	21%	55	56	2%	65	68	4%	78	82	5%
10	47	51	8%	69	71	3%	81	81	0%	94	96	2%
15	56	58	2%	78	79	1%	92	90	2%	106	106	0%
20	64	63	2%	86	85	1%	100	97	3%	115	113	1%
25	71	68	5%	93	90	3%	108	104	3%	122	120	2%
30	77	72	7%	98	95	3%	114	109	4%	128	125	3%

3. The 1.5-mm fracture width model experiments

Figure 4-6 shows the comparisons of the measured and history matched injection pressures corresponding to different injection rates and brine concentrations at the fracture width of 1.5 mm. Similar to the 0.5-mm and 1.0-mm fracture width experiments, the injection pressure increased with the increase of both injection flow rate and brine concentration. The simulation results matched the measured data moderately well and, again, it can be observed that at the same flow rate and brine concentration, the injection pressure of the 1.5-mm fracture width model experiment was lower than that of the previous 0.5-mm and 1.0-mm fracture width model experiments.

The pressure data obtained from both approaches and the calculated errors of the simulation with respect to the measured values for the 1.5-mm fracture width model experiments are summarized in Table 4-4. The simulation results gave close approximation for the total trend at each brine concentration but there was some discrepancy with each measurement point. With relatively low injection pressures of the large fracture width, the calculated errors in percentage were higher in this case in comparison to those of the previous cases with smaller fracture widths.

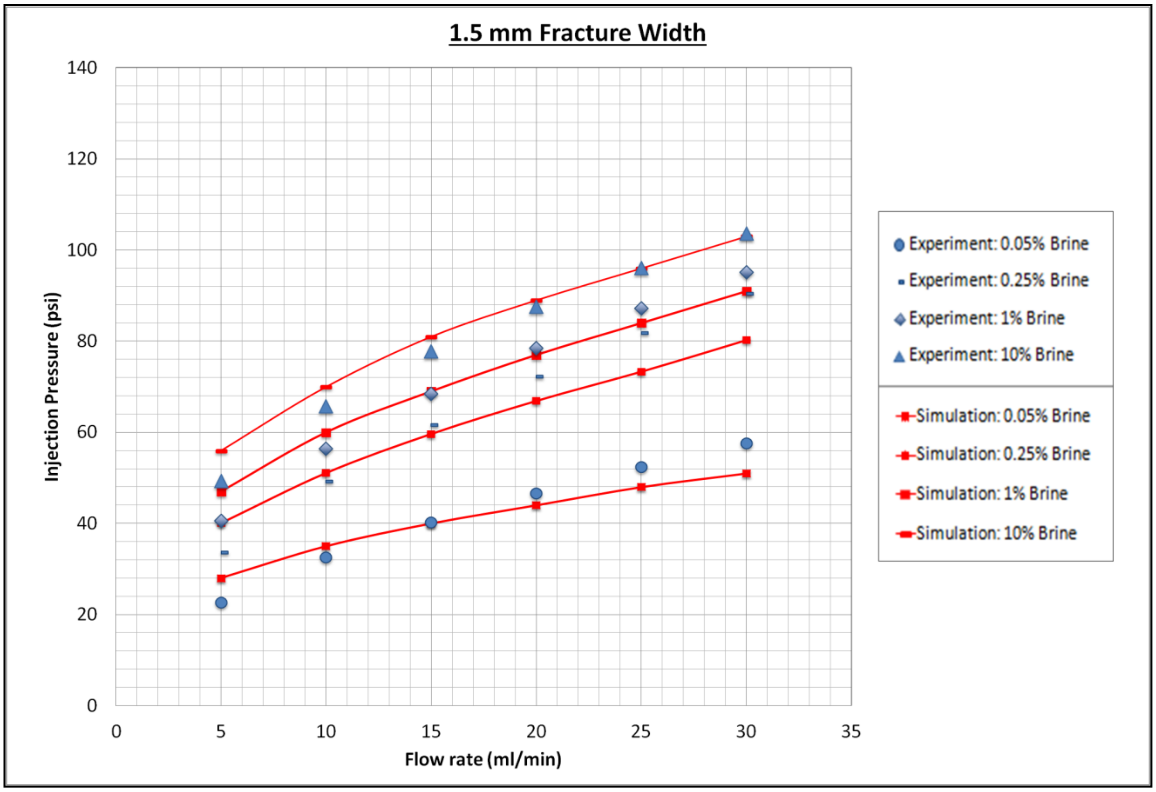


Figure 4 - 6. Injection pressure vs. flow rate, 1.5-mm fracture width model

Table 4 - 4. History match results for the 1.5-mm fracture width model

Flow rate (ml/min)	Pressure (psi)											
	0.05% Brine			0.25% Brine			1% Brine			10% Brine		
	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error	Experiment	Simulation	error
5	23	28	23%	34	40	19%	41	47	16%	49	56	13%
10	33	35	8%	49	51	4%	56	60	6%	66	70	6%
15	40	40	0%	62	60	3%	68	69	1%	78	81	4%
20	47	44	6%	72	67	7%	78	77	2%	88	89	2%
25	52	48	8%	82	73	10%	87	84	4%	96	96	0%
30	58	51	12%	90	80	11%	95	91	4%	104	103	1%

Summary and Conclusions:

1. PPG does not fully block the fracture opening. However, injected PPG can form a gel pack inside the opening and creating resistance to water flow.
2. PPG injection pressure increases with the increase of injection rate but the degree of its increase is not as high as that of the injection rate.
3. PPG injection pressure increases with the increase of brine concentration. The experimental results indicate that the softness or deformability of swollen particles is more dominant to PPG injection pressure than the particle size of the swollen PPG. Although the low salinity gives higher swelling ratio, the swollen particles in low salinity brine are softer or more deformable than that in high salinity brine.
4. PPG injection pressure decreases with the increase of fracture width. This is due to the less resistance to flow (higher permeability) of the increased fracture width.
5. UTGEL simulation can match with the experiment results moderately well. Albeit some discrepancy, the simulation results provide the same trends and level of magnitude of injection pressure response as those measured in each experiment.

4.2. CASE II: Two-phase Flow in a Sandpack Model

Objectives: To investigate the performance of PPG in improving waterflood recovery from a homogeneous sandpack model.

Materials and Experiment Setup: Figure 4-7 illustrates the flow chart of the experiment setup composed of a 40-mesh sandpack (1 inch in diameter and 20 inches in length); three syringe pumps and 3 accumulators for KCl brine, oil, and PPG injection; and four pressure transducers mounted on the inlet and on the pressure tips along the sand pack with a pressure recorder to monitor the pressure behavior of the injection process.

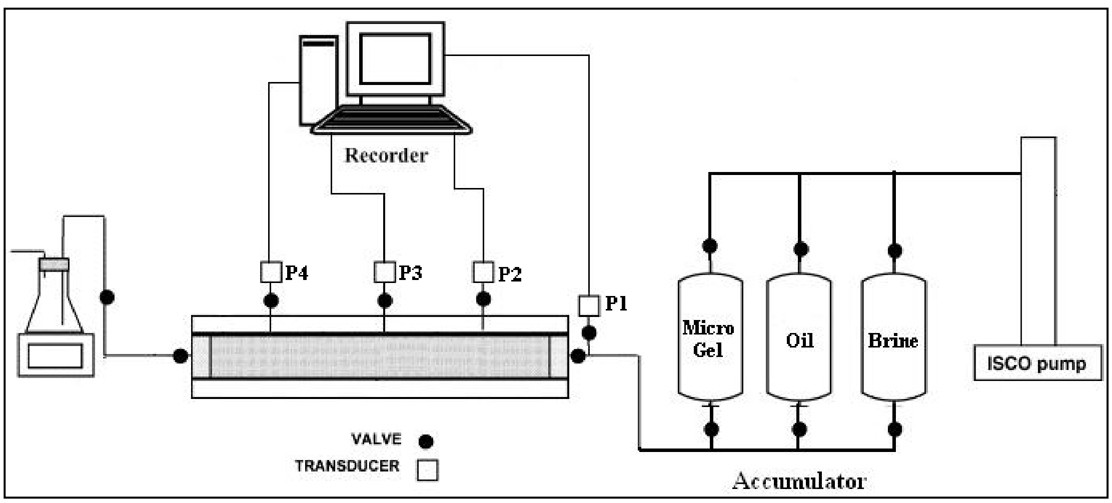


Figure 4 - 7. Sandpack experiment setup (Bai, 2014)

Experimental Procedure:

1. Saturate the sandpack with 1% KCl brine and calculate the pore volume.
2. Inject brine at different flow rates to calculate permeability.
3. Inject oil to displace the water and calculate the oil-in-place volume based on the water displaced.
4. At the constant injection rate of 2 ml/min, start displacing oil with brine, inject a few pore volumes of PPG (2000 ppm concentration), and displace PPG with brine again. Record the pressure, oil rate, and water rate with time to observe the injectivity, oil recovery, and water cut behavior.

Numerical Simulation: Using the data obtained from the experiment, we constructed a simple 1-D numerical model of the sandpack (Figure 4-8) and simulated the experiment to calibrate and verify the PPG mechanistic model developed and implemented in the UTGEL simulator. With most parameters known, the only parameters that needed to be adjusted in the simulation to match the water cut response and oil recovery were the permeability reduction factor, a_{kp} and n_{kp} (see Equation 3-9, Chapter 3). The input parameters used in the history match are summarized in Table 4-5. Complete input data of this simulation run can be found in Appendix A-2.

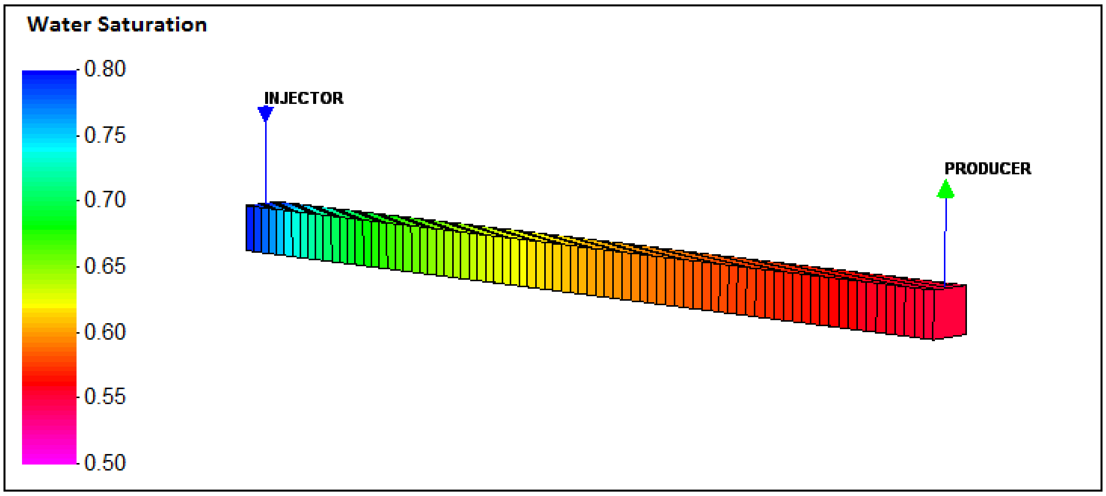


Figure 4 - 8. Simulation grids for the sandpack experiment

Table 4 - 5. UTGEL simulation input parameters for the sandpack experiment

Model	1-Dimentional Cartesian
Number of gridblocks	80 x 1 x 1
Δx, Δy, Δz	0.25, 1, 1 inch
Porosity	0.386
Permeability	27290 mD
Initial water saturation	0.12
Oil viscosity	37 cp
Water viscosity	1 cp
Temperature	72.5 °F
Outlet pressure	14.7 psi
Salinity	0.134 meq/ml
Injection / production rate	2 ml/min
Injection / production period	5.4 PV
PPG concentration	2000 ppm
PPG diameter	0.1 mm

Simulation Results:

In this experiment, first 2.5 PV of brine was injected as the pre-treatment waterflood, then approximately 1.2 PV of PPG suspensions was injected, and finally 1.7 PV of brine was injected to chase the PPG as the post-treatment waterflood. The comparison of the measured and simulated oil recovery is shown in Figure 4-9. It can be observed from the plot that the oil recovery was matched very closely for the entire pore volumes injected. The comparison of the water cut profile measured from the experiment and the water cut profile obtained from the history match attempt is demonstrated in Figure 4-10. It can be observed that the water cut reduction occurred after a while in response to PPG injection. The water cut reduced from almost 100% to approximately 80% before rising back to the previous high level. For this experiment, the history match could be considered moderately accurate, noting the equivalents in the water breakthrough time during the pre-treatment waterflood, the reduction in water cut, and the increase back in water cut during the post-treatment waterflood.

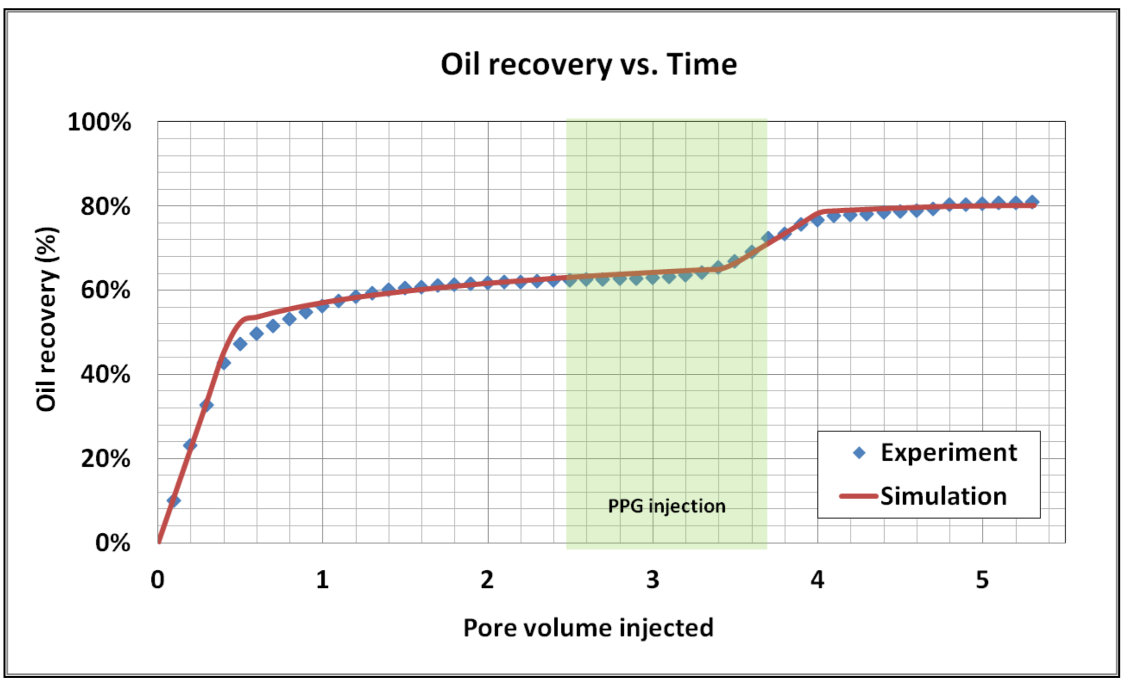


Figure 4 - 9. Oil recovery vs. time, sandpack experiment

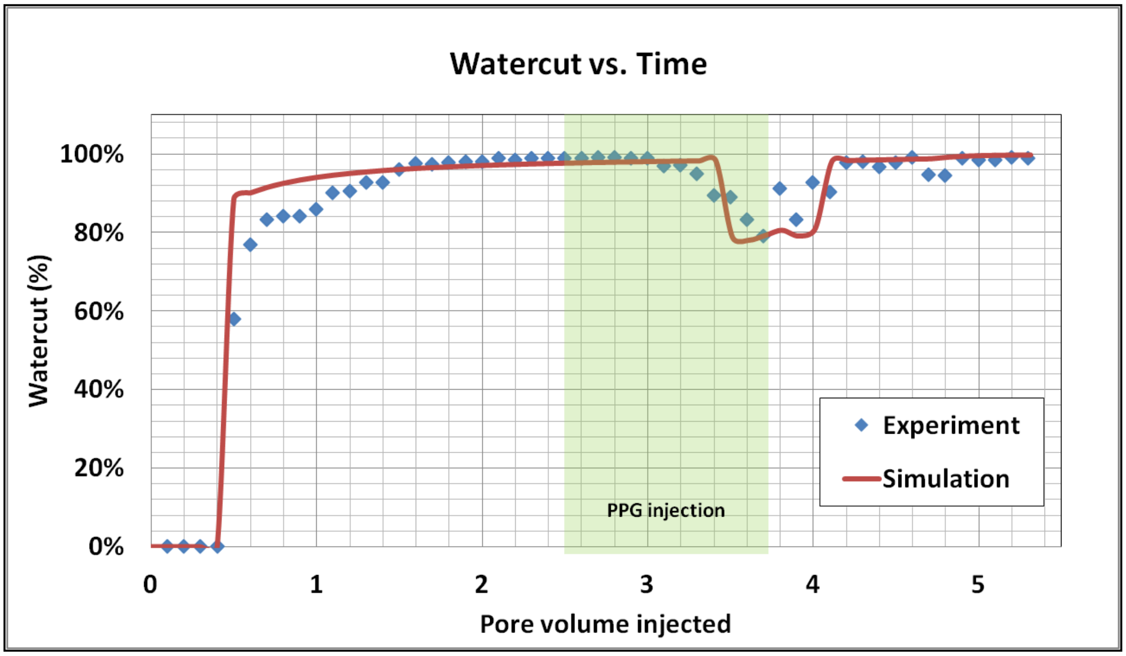


Figure 4 - 10. Water cut vs. time, sandpack experiment

Summary and Conclusions:

1. From the sandpack model experiment, PPG injection could lead to an increase in oil recovery. In this case, the waterflood recovery prior to PPG injection was 63%. The final recovery after PPG injection was 80%. The incremental recovery from 1.2 PV of PPG injection was 17%.
2. The water cut reduction was observed after the injection of PPG. In this case, the reduction of water cut was as significant as 20%. However, it went back up to the previous high level of water cut (99%) during the subsequent brine injection.
3. UTGEL simulation could match the performance of PPG in improving oil recovery for a two-phase flow in a sandpack model. The water cut behavior was matched by adjusting the permeability reduction factor and the PPG retention parameters.

4.3. CASE III: Two-phase Flow in a Coreflood

Objectives: To investigate the performance of PPG in improving waterflood recovery from an actual coreflood.

Materials and Experiment Setup: Figure 4-11 illustrates the flow chart of the experiment setup composed of an actual core of Roubidoux sandstone sample from Missouri (1 inch in diameter and 6 inches in length); a pressure transducer mounted to the inlet to monitor the injection pressure; pumps and accumulators for brine, oil, and PPG injection; a core holder and a confining pressure pump; and a computer used as a recorder and data processor.

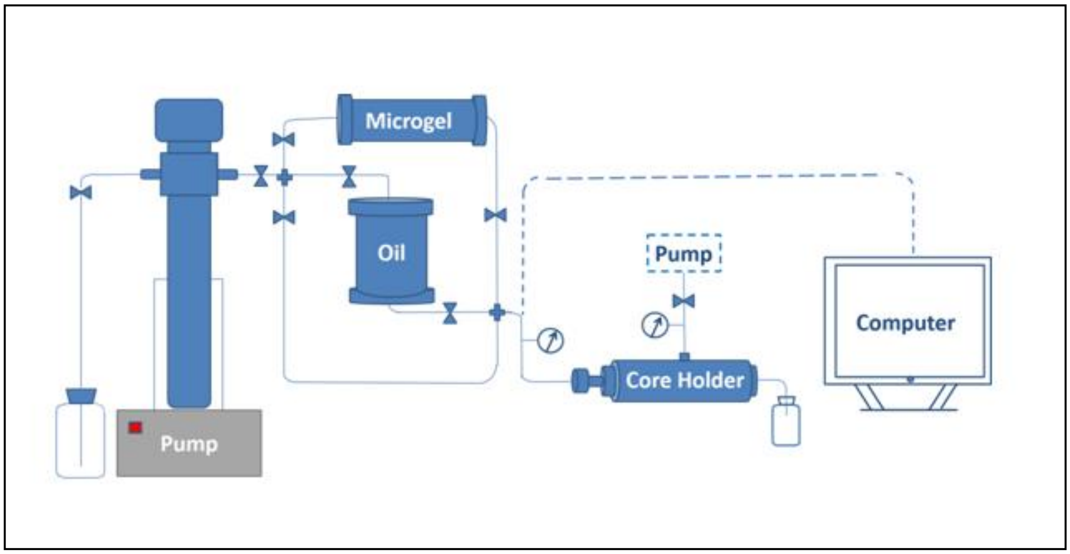


Figure 4 - 11. Coreflood experiment setup (Bai, et al., 2014)

Experimental Procedure:

1. Saturate the sandstone core with 1% KCl brine and calculate the porosity.
2. Pack the core in the core holder with 600 psi confining pressure.
3. Inject brine at different flow rates to calculate the permeability.
4. Inject oil to displace the water and calculate the oil-in-place volume based on the water displaced.
5. At the constant injection rate of 1 ml/min, start displacing oil with brine, inject few pore volumes of PPG (2000 ppm concentration), and displace PPG with brine again. Record the pressure, oil rate, and water rate with time to observe the injectivity, oil recovery, and water cut behavior.

Numerical Simulation: Using the data obtained from the experiment, we constructed a simple 1-D numerical model of the coreflood (Figure 4-12) and history matched the experimental results. This exercise gives further verification of PPG transport model in a sandstone core with distribution of pore and pore throat sizes. With most parameters known, the only parameters adjusted to match the water cut and oil recovery were the permeability reduction factor, a_{kp} and n_{kp} (see Equation 3-9, Chapter 3). The history match input parameters are summarized in Table 4-6. Complete input data can be found in Appendix A-3.

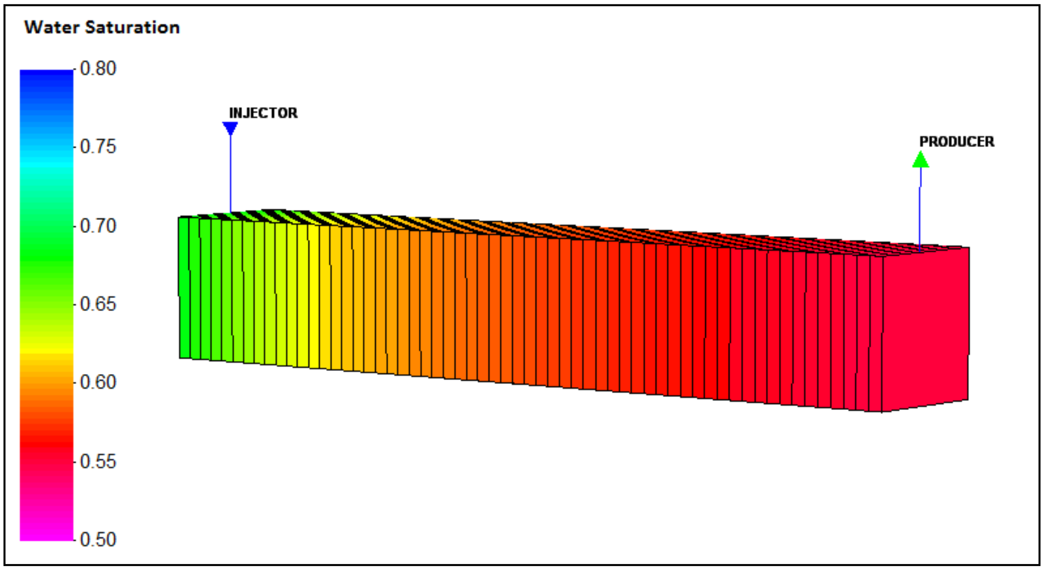


Figure 4 - 12. Simulation grids for the coreflood experiment

Table 4 - 6. UTGEL simulation input parameters for the coreflood experiment

Model	1-Dimentional Cartesian
Number of gridblocks	60 x 1 x 1
Δx, Δy, Δz	0.1, 1, 1 inch
Porosity	0.156
Permeability	192.2 mD
Initial water saturation	0.005
Oil viscosity	37 cp
Water viscosity	1 cp
Temperature	72.5 °F
Outlet pressure	14.7 psi
Salinity	0.134 meq/ml
Injection / production rate	1 ml/min
Injection / production period	35.6 PV
PPG concentration	2000 ppm
PPG diameter	100 µm

Simulation Results:

The history matching for the coreflood experiment was conducted using UTGEL to match the total oil recovery and water cut profile. The comparison of the oil recovery measured from the experiment and the oil recovery obtained from the simulation history match is illustrated in Figure 4-13. In this experiment, first 5.4 PV of brine was injected as the pre-treatment waterflood, then approximately 23 PV of PPG suspension was injected as the PPG treatment, and finally 7.2 PV of brine was injected to chase the PPG suspension as the post-treatment waterflood. It can be observed from the figure that the simulation matched the experimental oil recovery moderately well for the entire volume injected.

The comparison of the water cut profile measured from the experiment and the water cut profile obtained from the history match attempt is shown in Figure 4-14. It can be observed that the water cut slightly dropped for a short period in response to PPG injection before rising back to the previous high level. The reduction in water cut was rather minimal (less than 10%) for this experiment. The simulation matched the water breakthrough time during the pre-treatment waterflood and the reduction in water cut reasonably well even though it did not match the minor water cut fluctuation at the later part toward the end of the process during the post-treatment waterflood.

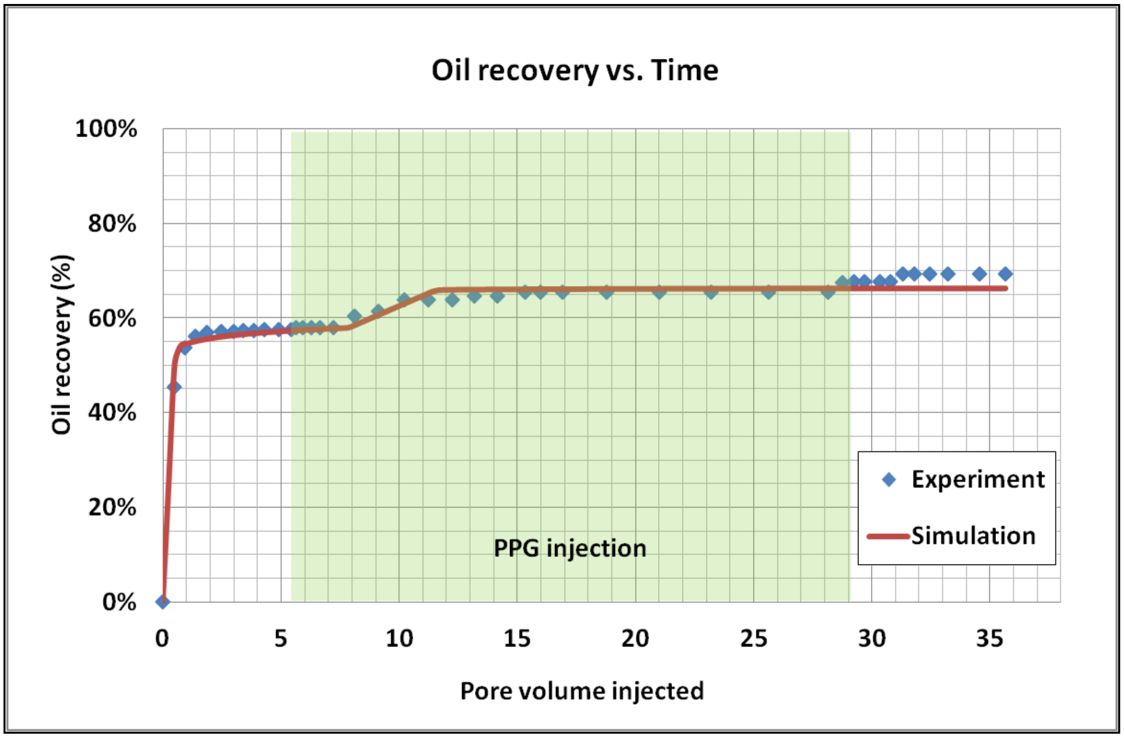


Figure 4 - 13. Oil recovery vs. time, coreflood experiment

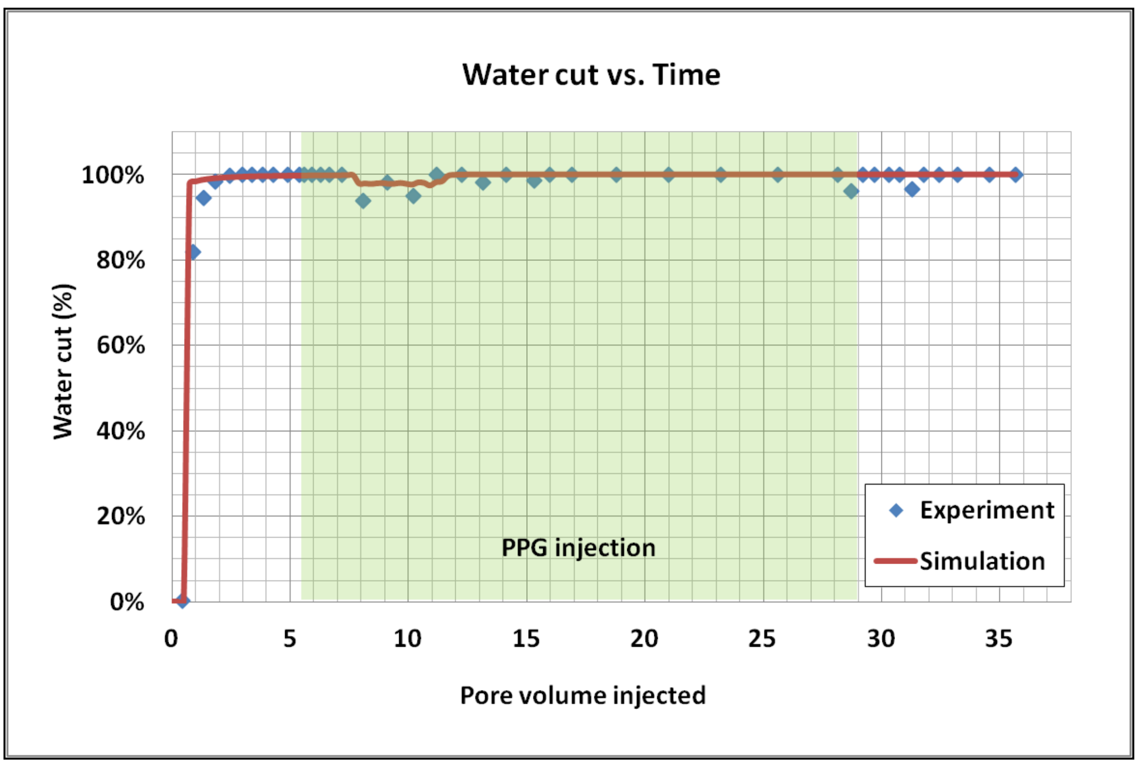


Figure 4 - 14. Water cut vs. time, coreflood experiment

Summary and Conclusions:

1. From the coreflood experiment, PPG injection could lead to an increase in oil recovery from the sandstone core. In this case, the waterflood recovery was 58% prior to PPG injection. The final recovery after PPG injection was 68%. The incremental recovery from the total of 23 PV of PPG injection was 10%. For homogeneous flood, PPG can help improving recovery by creating a resistance factor and sometimes reducing the residual oil by lowering the capillary pressure.
2. The water cut reduction was observed after the injection of PPG. However, it went back up to the previous water cut of 99% after only a few pore volumes of PPG injection. Also, the magnitude of water cut reduction was small compared to the sandpack experiment. The lower impact from PPG in this experiment could be because the permeability of the sandpack is much higher than the sandstone core (27 D vs. 192 mD). The particle gels used in both experiments were commercial gels, which were usually designed to transport through high permeability conduits and not penetrate into conventional permeability rocks.
3. UTGEL could match the performance of PPG in improving oil recovery during two-phase flow in a sandstone core. The water cut behavior was closely matched by tuning the permeability reduction factor and PPG retention input parameters

4.4. CASE IV: Two-phase Flow in a Sandpack Model with Different PPG Injection Rates

Objectives: To study the impact of PPG on water cut of a two-phase flow in a homogeneous sandpack model with various PPG injection rates.

Materials and Experiment Setup: Figure 4-15 illustrates the flow chart of the experiment setup composed of a 20-mesh sand pack (2.5 cm in diameter and 91.4 cm in length); three syringe pumps and 3 accumulators for KCl brine, oil, and PPG injection; and four pressure transducers mounted on the inlet and on the pressure tips along the sand pack with a pressure recorder to monitor the pressure behavior of the injection process.

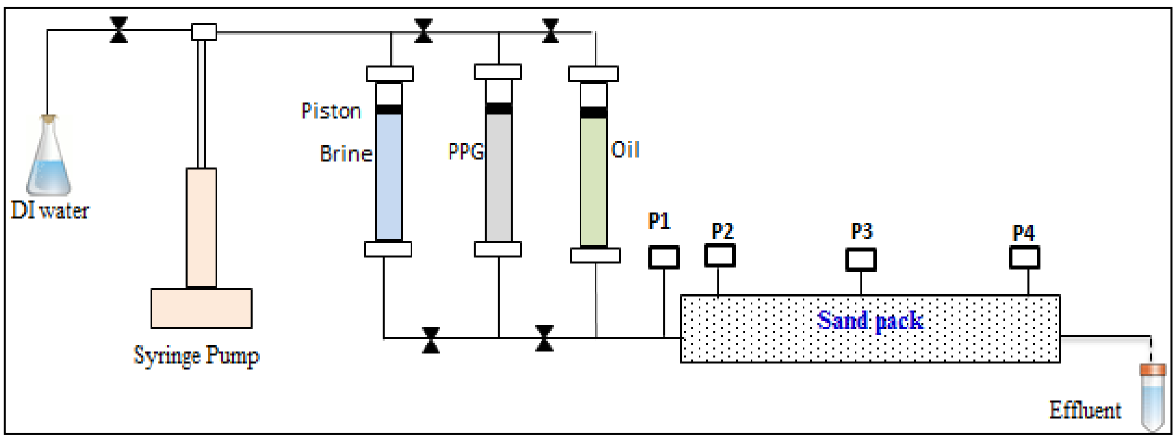


Figure 4 - 15. Sandpack experiment with different PPG injection rates setup (Bai, et al., 2014)

Experimental Procedure:

1. Saturate the sandpack with 12.5% NaCl brine and calculate the pore volume and porosity.
2. Inject brine at different flow rates to calculate the permeability.
3. Inject oil to displace the water and calculate the oil-in-place volume based on the water displaced.

4. Start displacing oil with brine at a flow rate of 2 ml/min. Inject PPG (2000 ppm concentration) with different flow rates varied from 1 ml/min to 7 ml/min. Then, displace PPG with brine again at a flow rate of 2 ml/min. Record the pressure, oil rate, and water rate with time to observe the injectivity, oil recovery, and water cut behavior.

Numerical Simulation: We constructed 1-D numerical model (Figure 4-16) of the sandpack experiment. Only parameters that needed to be adjusted to match the water cut response and oil recovery were the permeability reduction factor parameters, a_{kp} and n_{kp} (see Equation 3-9, Chapter 3). In addition, to match the injection pressure at different rates of PPG injection with time, the viscosity parameters were also adjusted accordingly. The input parameters used in this history match model are given in Table 4-7. Complete input data of this simulation run can be found in Appendix A-4.

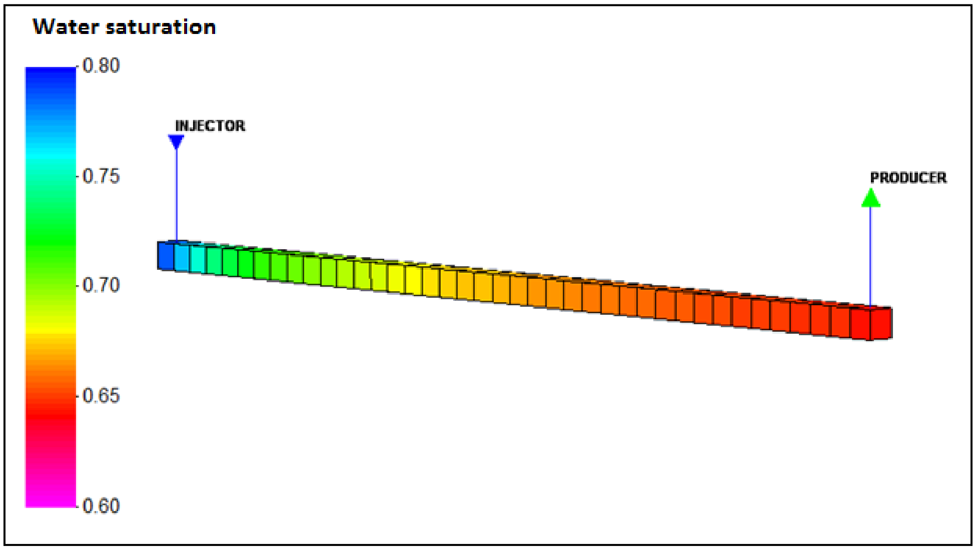


Figure 4 - 16. Simulation grids for the sandpack experiment with different PPG injection rates

Table 4 - 7. UTGEL simulation input parameters for the sandpack experiment with different PPG injection rates

Model	1-Dimentional Cartesian
Number of gridblocks	40 x 1 x 1
Δx, Δy, Δz	2.285, 2.5, 2.5 cm
Porosity	0.364
Permeability	27 Darcy
Initial water saturation	0.310
Oil viscosity	37 cp
Water viscosity	1 cp
Temperature	72.5 °F
Outlet pressure	14.7 psi
Salinity	0.0336 meq/ml
Injection / production rate	2 ml/min
Injection / production period	16 PV
PPG concentration	800 ppm
PPG particle diameter size	180 µm

Simulation Results:

The comparison of the oil recovery measured from the experiment and the oil recovery obtained from the simulation history match is illustrated in Figure 4-17. In this experiment, first 1.5 PV of brine was injected as the pre-treatment waterflood, then approximately 13 PV of PPG suspension was injected as the PPG treatment, and finally another 1.5 PV of brine was injected to chase the PPG suspension as the post-treatment waterflood. It can be observed from the figure that the simulation results matched the experimental oil recovery reasonably well for the entire pore volume injected.

The comparison of the measured and simulated water cut profile is shown in Figure 4-18. The measured water cut in the experiment rather fluctuated between 93% and 100% with an average water cut of approximately 98% while the simulation water cut was rather steady at roughly 98% during the PPG treatment and went up to 100% towards the end of the experiment.

Lastly, the injection pressures obtained from the simulation compared to the measurements in the experiment during the injection rate changing period are shown in Figure 4-19. The injection rate of PPG suspension was altered from 2 ml/min to 1, 3, 4, 5, 6, and 7 ml/min during the short period of time between 12.7 to 14.1 PV injected. It can be seen that the pressure had been building up from the start of PPG injection until the rate was altered at 12.7 PV injected. As the rate fluctuated, the corresponding injection pressure also changed in the same direction. The magnitude of each pressure change as a function of the injection rate from the simulation was well matched with the experimental value for this case.

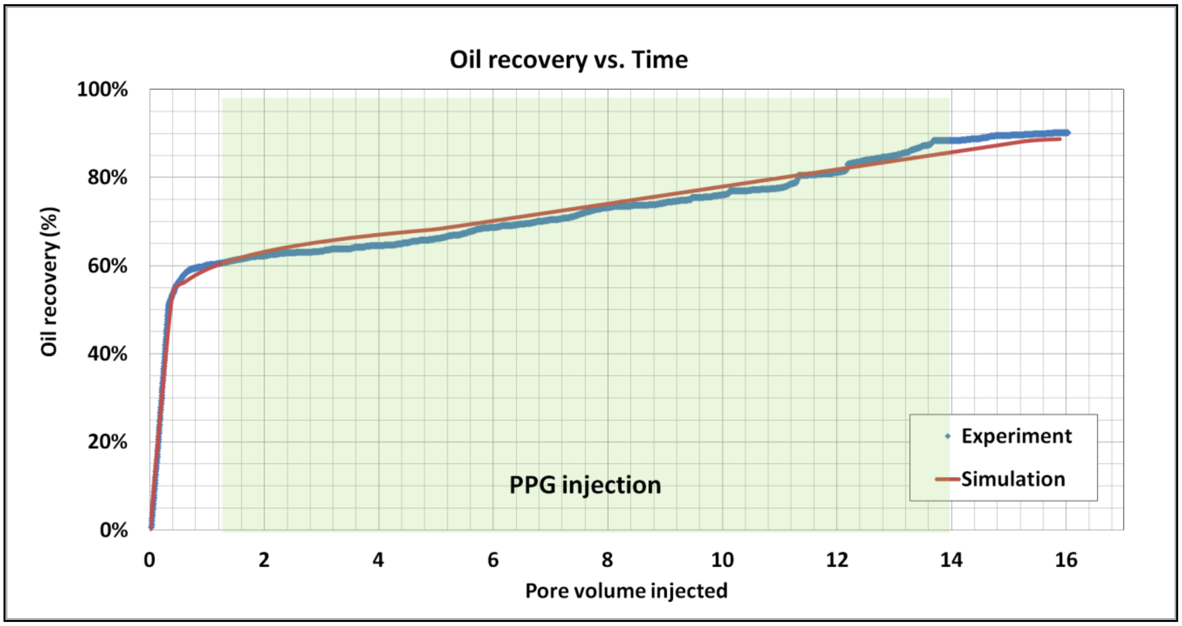


Figure 4 - 17. Oil recovery vs. time, sandpack experiment with different PPG injection rates

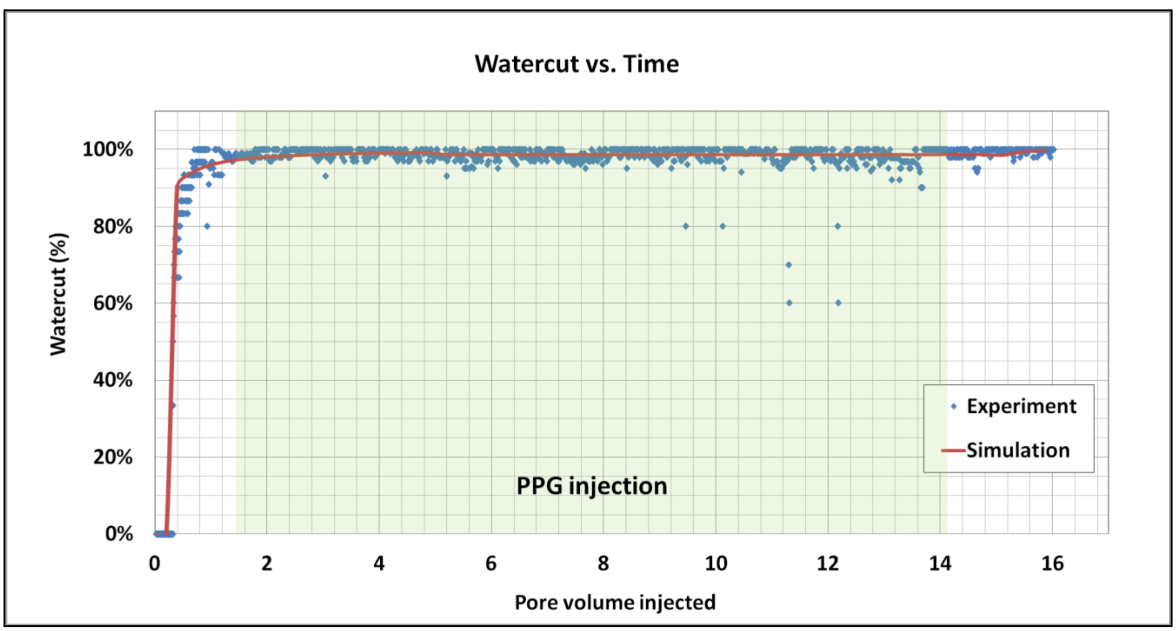
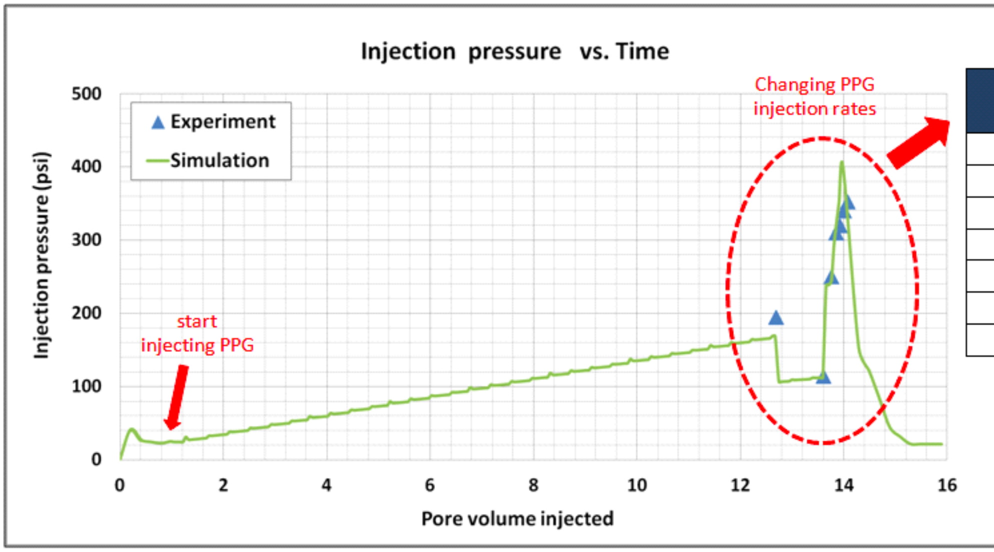


Figure 4 - 18. Water cut vs. time, sandpack experiment with different PPG injection rates



PV	Qinj (ml/min)
12.7	2
13.6	1
13.8	3
13.9	4
13.9	5
14.0	6
14.1	7

Figure 4 - 19. Injection pressure vs. time, sandpack experiment with different PPG injection rates

Summary and Conclusions:

1. The sandpack experiment indicated that PPG injection increased oil recovery compared to waterflooding. The waterflood recovery was approximately 60% prior to PPG injection. The final recovery after PPG injection was 88%. The incremental recovery from the total of 13 PV of PPG injection was 28% OOIP.
2. The response to PPG was fast and the water cut reduction was observed after the injection of PPG. It mostly fluctuated in within 93% and 100% with an average water cut of 98%.
3. UTGEL could match the performance of PPG in improving oil recovery in the sandpack. Permeability reduction factor and gel retention model parameters were adjusted to match the amount and the timing of the water cut reduction with the observed data. Although the simulation could not reflect the fluctuation of the water cut, it gives a similar trend with an average value.
4. The injection pressure of PPG as a function of injection rate can be well history matched by adjusting the viscosity model input parameters.

4.5. CASE V: Two-phase flow in a parallel sandpack model

Objectives: To study PPG performance when injected into a simple heterogeneous model consisting of two sandpack layers with different permeabilities.

Materials and Experiment Setup: Figure 4-20 illustrates the flow chart of the experiment setup composed of two sand packs (2.6 cm in diameter and 20 cm in length); three syringe pumps and 3 accumulators for KCl brine, oil, and PPG injection; and four pressure transducers mounted on the inlet to monitor the pressure behavior of the injection process.

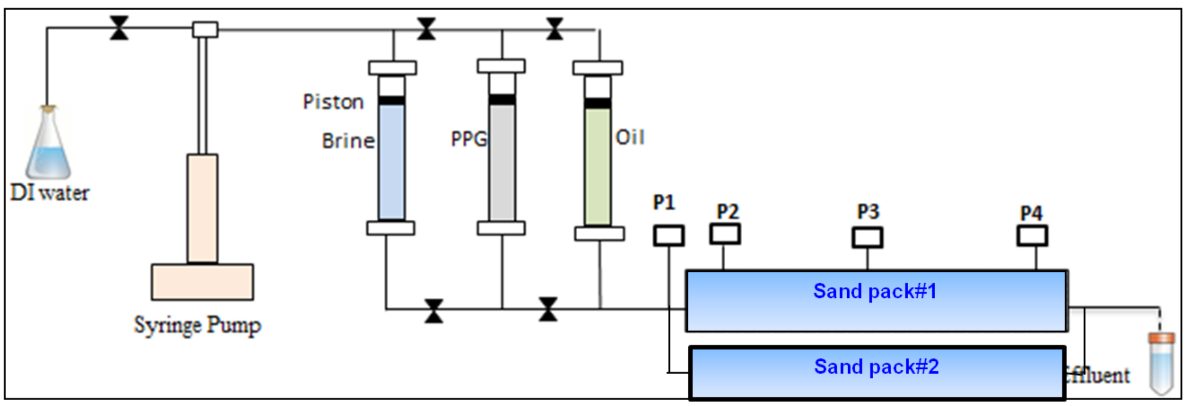


Figure 4 - 20. Parallel sandpack experiment setup (Bai, et al., 2014)

Experimental Procedure:

1. Inject brine at different flow rates to calculate the permeability of each sand pack.
2. Saturate each sandpack by injecting oil at a flow rate of 1 ml/min.
3. Set up the sandpack in parallel tubes.
4. With a constant flow rate of 1 ml/min, start displacing oil into both tubes with 1% NaCl brine. Inject PPG (2000 ppm concentration) for 0.5 PVs. Then, displace PPG with brine again until no oil is produced to obtain the recovery factor. Record the pressure, oil rate, and water rate with time to observe the injectivity, oil recovery, and water cut behavior.

Numerical Simulation: 2-D numerical model (Figure 4-21) was set up to history the parallel sandpack results. Water cut and oil recovery results were matched by adjusting the permeability reduction factor parameters, a_{kp} and n_{kp} (see Equation 3-9, Chapter 3). In addition, to match the injection pressure at different rates of PPG injection with time, the viscosity parameters were also adjusted accordingly. The input parameters used in this history match model are given in Table 4-8. Complete input data of this simulation run can be found in Appendix A-5.

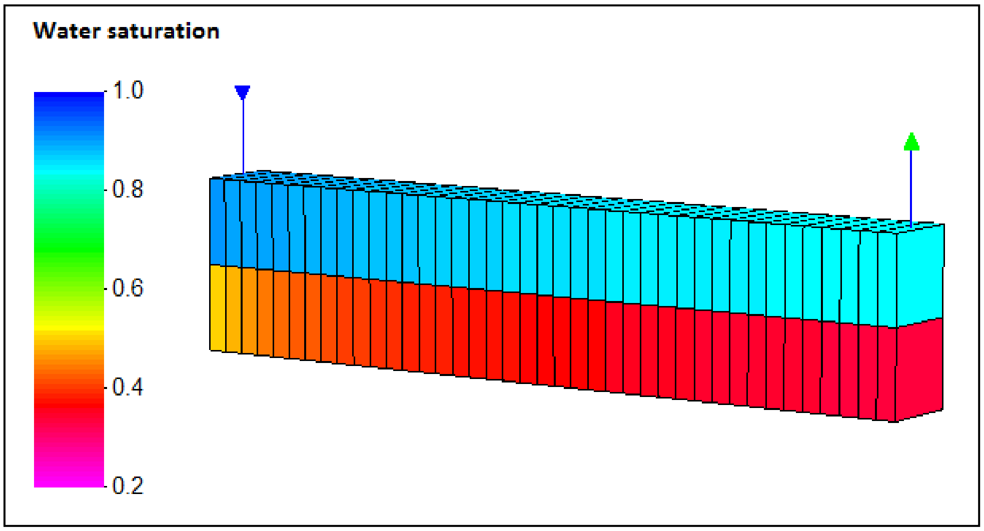


Figure 4 - 21. Simulation grids for the parallel sandpack experiment

Table 4 - 8. UTGEL simulation input parameters for the parallel sandpack experiment

Model	2-Dimentional Cartesian
Number of gridblocks	40 x 1 x 2
Δx, Δy, Δz	0.5, 2.1, 2.1 cm
Porosity	0.272, 0.375
Permeability	6778, 1005 mD
Ratio of Kv/Kh	0
Initial water saturation	0.26, 0.18
Oil viscosity	195 cp
Water viscosity	1 cp
Temperature	72.5 °F
Outlet pressure	14.7 psi
Salinity	0.17 meq/ml
Injection / production rate	1 ml/min
Injection / production period	5.23 PV
PPG concentration	2000 ppm
PPG particle diameter size	0.08 mm

Simulation Results:

The comparison of measured and simulated oil recovery for the parallel sandpack model experiment is shown in Figure 4-22. Firstly, brine was injected as the pre-treatment waterflood for 2.8 PV, then approximately 0.3 PV of PPG suspension was injected as the PPG treatment, and lastly 2.1 PV of brine was injected to chase the PPG suspension as the post-treatment waterflood. Figure 4-22 suggests a good match between experimental and simulated oil recoveries with a minor discrepancy.

The comparison of the water cut profile measured from the experiment and the water cut profile obtained from the history match is demonstrated in Figure 4-23. It can be observed that the water cut dropped almost right after PPG injection before gradually rising up during the post-treatment waterflood. The reduction in water cut was rather significant for this experiment, exceeding 25%. The simulation also matched the water breakthrough time during the pre-treatment waterflood and the reduction in water cut fairly well for this case.

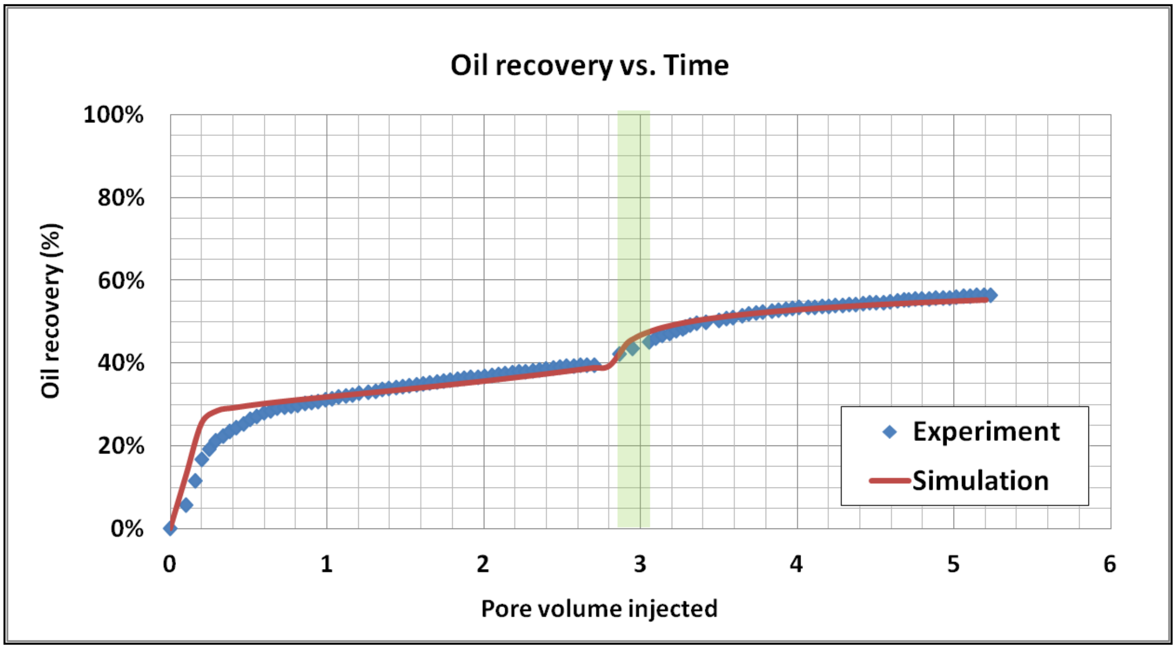


Figure 4 - 22. Oil recovery vs. time, parallel sandpack experiment

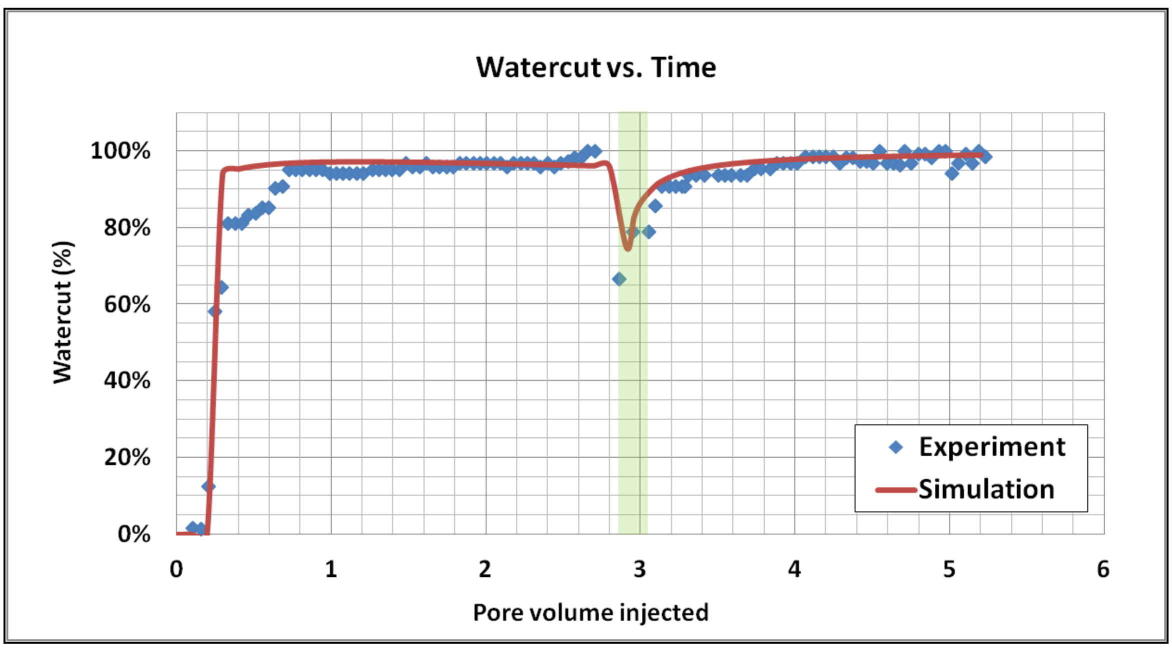


Figure 4 - 23. Water cut vs. time, parallel sandpack experiment

Summary and Conclusions:

1. The parallel sandpack experiment indicated PPG injection increased oil recovery compared to waterflooding. The overall waterflood recovery was 42%OOIP prior to PPG injection. The final recovery after PPG injection was 55%OOIP. The incremental recovery from the total of 0.3 PVs of PPG injection was 13%OOIP. For heterogeneous flood, PPG improves oil recovery by blocking the high permeability layer and diverting the water to the lower permeability layer.
2. The response to PPG was fast. The maximum water cut reduction of more than 25% was observed after the injection of PPG.
3. PPG can selectively penetrate into the higher permeable layer while minimizing its penetration into the lower permeable layer or unswept zone.
4. UTGEL could match the performance of PPG in improving oil recovery in the parallel sandpack which represented a degree of heterogeneity in the experiment setup. Permeability reduction factor and gel retention model parameters were adjusted to match the amount and the timing of the water cut reduction with the experimental data.

Chapter 5: Synthetic Case Simulation

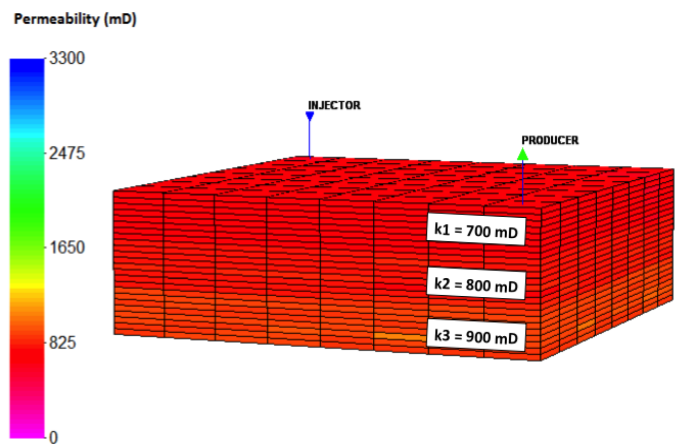
5.1. Simulation of PPG Treatment in Layered Reservoir Models

Objectives: To investigate the benefit of a PPG treatment in improving waterflood vertical sweep efficiency in layered reservoirs with different degrees of heterogeneities, five synthetic reservoir models were constructed to simulate PPG treatments and the impacts on conformance control and subsequent improved oil recovery.

Model Description:

Five reservoir numerical models were generated; the reservoir was 40 ft long, 40 ft wide, and 12 ft thick with a pair of injection and production wells located at the diagonally opposite corners. All models consisted of 3 numerical layers with different average permeabilities per layer. With all other parameters assumed the same, the degree of permeability contrast was increased progressively from case I to case V. This was done to represent the increase in permeability contrast and heterogeneity, which can also be expressed by the Dykstra Parsons coefficient (V_{DP}). Demonstrated in Figure 5-1 are the simulation grids with the assigned permeability distributions. Table 5-1 presents the input parameters for cases I to V. For all cases, to be compared with the base case of 8 pore volumes (PV) of waterflood, 3 PVs of PPG suspension was injected after 2 PV of pre-treatment water injection and followed by 3 PVs of post-treatment water injection.

Figure 5 - 1. The five models generated for layered reservoir model case study

<table>
<tr><th>Case</th><th>Simulation Grid Model</th></tr>
<tr><td>I. Very low permeability contrast
V_{DP} = 0.11</td><td>
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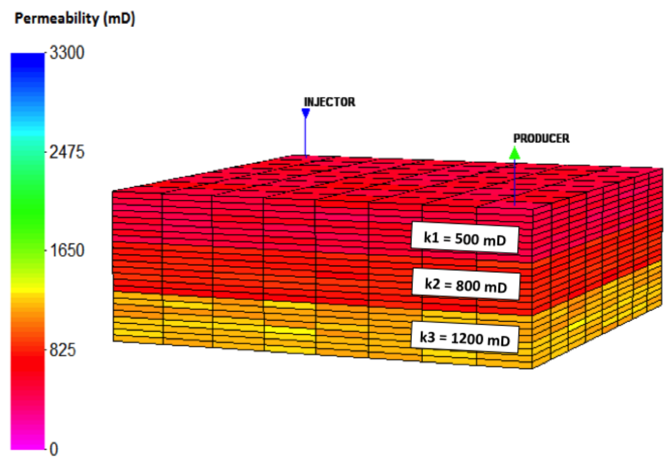
<tr><td>II. Low permeability contrast
V_{DP} = 0.30</td><td>
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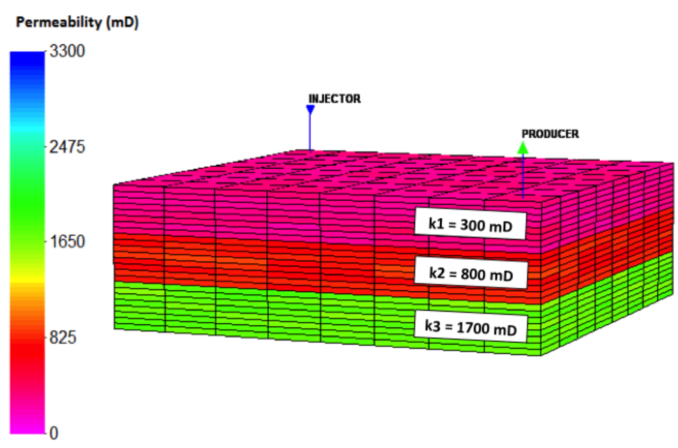
<tr><td>III. Intermediate permeability contrast
V_{DP} = 0.53</td><td>
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Figure 5 - 1. The five models generated for layered reservoir model case study (cont.)

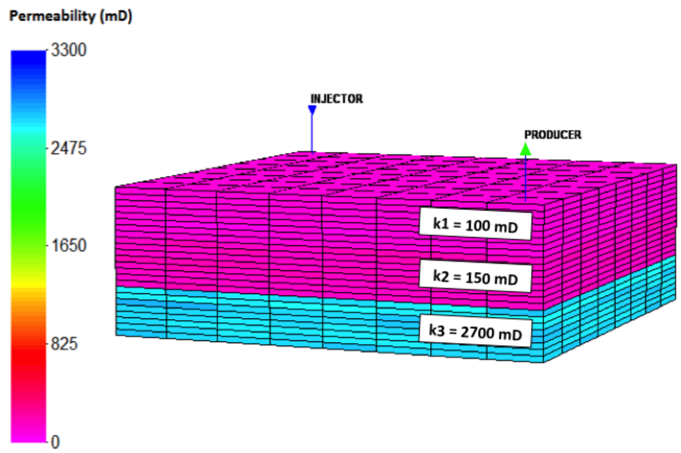
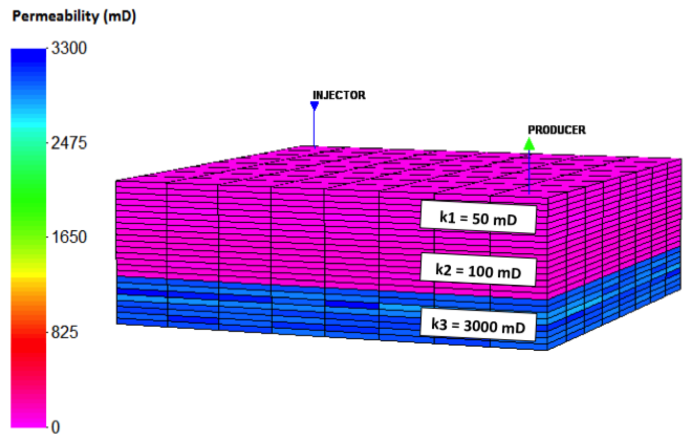
Case	Simulation Grid Model
IV. High permeability contrast V_{DP} = 0.74	
V. Very high permeability contrast V_{DP} = 0.81	

Table 5 - 1. Input parameters for reservoir models cases I to V

Model	3-Dimentional Cartesian
Number of gridblocks	8 x 8 x 24
Δx, Δy, Δz	5, 5, 0.5 ft
Porosity	0.25
Permeability	Varied from cases I to V, *see Figure 5-1*
Ratio of Kv/Kh	0.001
Initial water saturation	0.12
OOIP	752 STB
Oil viscosity	37 cp
Water viscosity	1 cp
Total injection period	8 PV
PPG concentration	750 ppm
PPG particle diameter size	0.1 mm

Simulation Results:

Table 5-2 shows the recoveries obtained for all five cases. From cases I to V, the only parameter adjusted for sensitivity analysis was the degree of permeability contrast (k1: k2: k3). The results indicated that incremental recovery obtained from PPG treatment increases significantly with the increase in the degree of heterogeneity. As expected, the total recovery as well as the waterflood recovery declined from cases I to V with the increase in the Dykstra Parsons coefficient (i.e. heterogeneity). However, the PPG incremental recovery behaved in the opposite trend. While injecting PPG in case I resulted in 8% incremental recovery, injecting PPG in case V gave 28%.

Table 5 - 2. Simulation results obtained from cases I to V

Case	Permeability Contrast	k1:k2:k3	Dykstra Parson Coefficient	WF Recovery	Incremental Recovery from PPG	Total Recovery
I	Very Low	700:800:900	0.11	64%	8%	72%
II	Low	500:800:1200	0.30	63%	9%	72%
III	Intermediate	300:800:1700	0.53	61%	10%	71%
IV	High	100:150:2700	0.74	48%	16%	63%
V	Very High	50:100:3000	0.81	36%	28%	64%

Figures 5-2 and 5-3 illustrate the oil recovery profile for each scenario with and without the PPG treatments. In all cases, the PPG treatment was shown to improve the oil recovery. However, it can be seen that the magnitudes of the incremental oil recovery varied considerably. For reservoirs with high degrees of heterogeneity, i.e. reservoirs with Dykstra Parsons coefficients of more than 0.7, PPG treatment efficiently increased recovery factor by 15-30%OOIP. In contrast, for reservoirs with low to intermediate degrees of heterogeneity, i.e. reservoirs with Dykstra Parsons coefficients of less than 0.5, PPG treatment only improved the recovery efficiency by less than 10%OOIP.

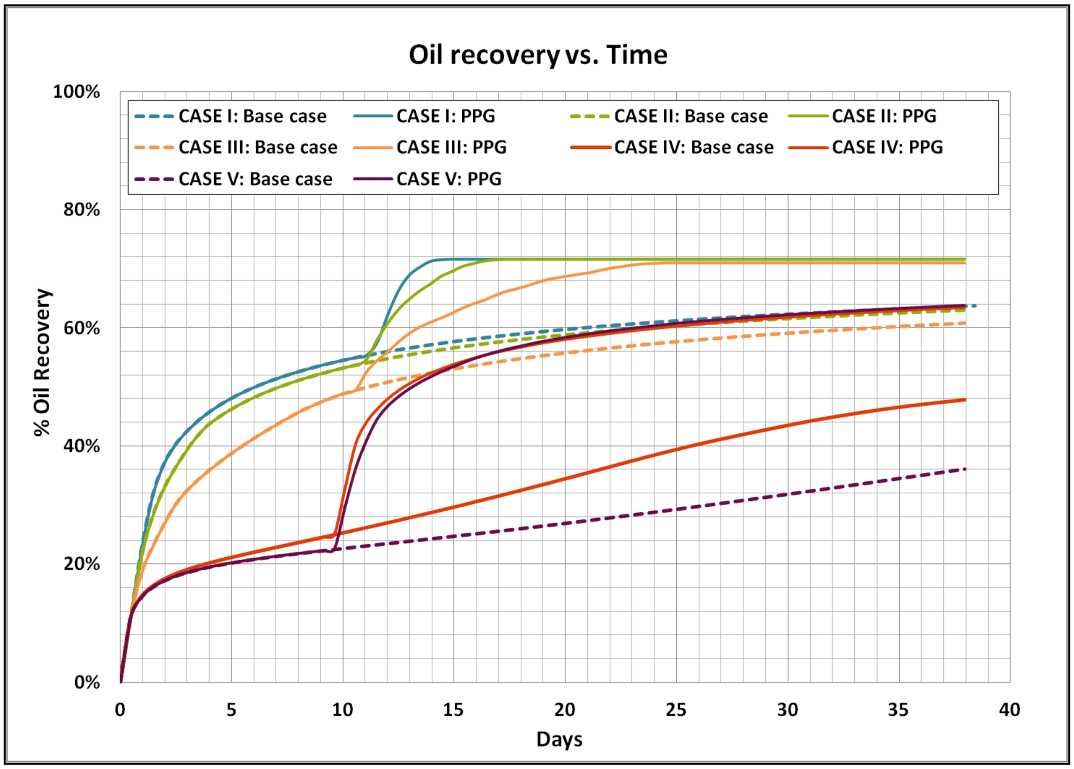


Figure 5 - 2. Oil recovery vs. time for cases I to V, waterflood (base case) and PPG treatment

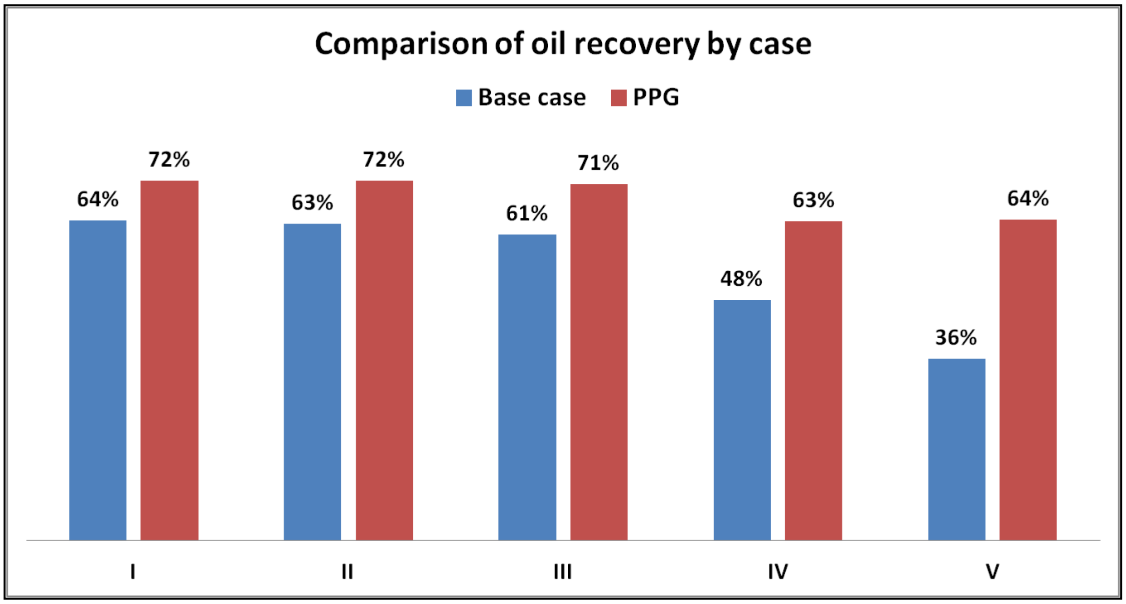


Figure 5 - 3. Comparison of oil recovery for cases I to V, waterflood (base case) and PPG treatment

Figure 5-4 shows the plot of incremental recovery from PPG versus Dykstra Parsons coefficient. A rough correlation may be established so that one can estimate the incremental oil recovery obtained from PPG treatment from reservoir heterogeneity (expressed by Dykstra Parsons Coefficient). This can be useful in evaluating a PPG treatment project or comparing PPG treatment with other EOR (Enhanced Oil Recovery) options such as polymer injection, CO_2 injection, or other chemical treatments. For example, when considering a heterogeneous reservoir with a Dykstra Parsons Coefficient of 0.6, in a very early assessment, one could use 14% as a ballpark figure for additional recovery associated from a PPG treatment. An initial economic analysis can be conducted to evaluate the viability of the PPG project with the knowledge of volume-in-place, timing of operations, and cost of treatments. However, this study has not yet incorporated a sensitivity analysis of many other parameters that affect the performance of a PPG treatment; namely, PPG concentration, injection period, injection rate, etc. Once the treatment has been chosen for implementation, a detailed optimization study considering all design parameters will need to be conducted for each reservoir.

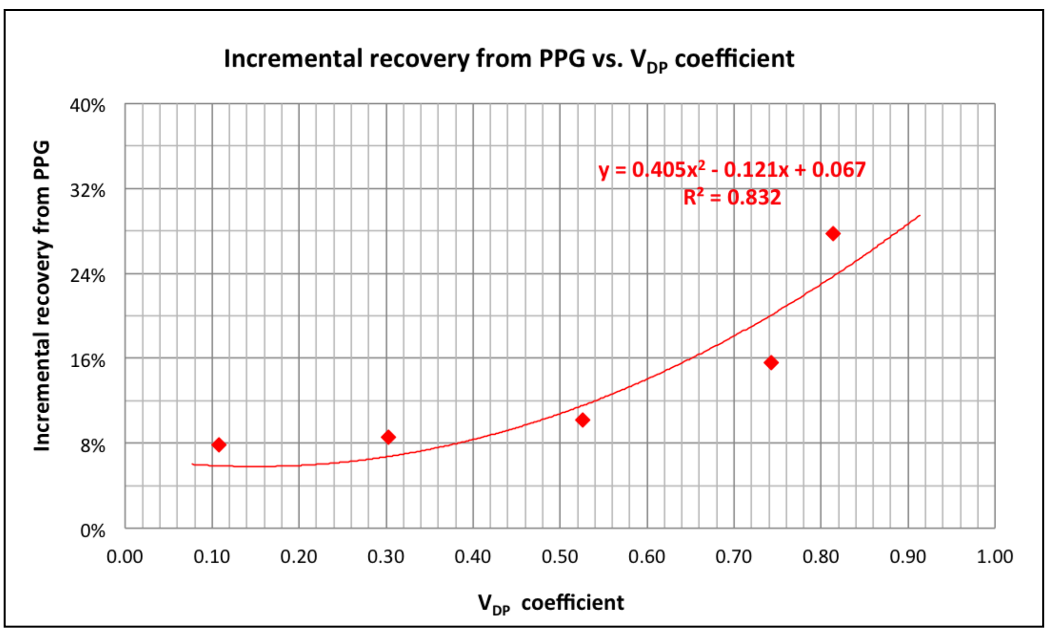


Figure 5 - 4. Incremental oil recovery from PPG treatments vs. V_{DP}

Summary and Conclusions:

It can be inferred from the simulation results that the benefit of PPG treatment is larger when reservoir is more heterogeneous for the cases studied in this chapter. The results are consistent with the fact that PPG treatment aims to reduce the fluid channeling through the high permeability streaks or fracture conduits. The success of a PPG treatment depends mostly on whether or not PPG can selectively penetrate into the highly permeable channels while minimizing its penetration into lower permeable or unswept zones. In the case of low permeability contrast or a fairly homogeneous reservoir, waterflood recovery alone (or base case recovery) can reach approximately 60% without any PPG treatment attempts. This means that injecting PPG in homogeneous reservoirs is not beneficial and not recommended. In early phase of selecting a conformance control or PPG treatment to improve an oil recovery, a Dykstra Parsons coefficient may be used along with other factors to approximate the potential incremental gain.

5.2. Simulation of PPG Treatment in Reservoirs With Conduits

Objectives:

As reported in the recent study of PPG extrusion through opening conduits (Imqam, et al., 2014), PPG can effectively reduce the permeability of an open conduit of several Darcy with the resistance factor (permeability reduction factor) on the order of 10^2 to 10^5. To investigate PPG's blocking efficiency and simulate its application in improving waterflood sweep efficiency, two reservoir models were constructed and simulated for both waterflood and PPG treatments.

Model Description:

Conduit case I

The Conduit case I model was a simple rectangular model with single matrix permeability. A long lateral conduit was placed in the middle of the model with a pair of injection and production wells at each end of the conduit on the edges of the model, as shown in Figure 5-5. Note that the matrix grid was made transparent in order to display the conduit located within the reservoir model. Including the conduit, which was placed explicitly by adding 1-ft layers vertically and horizontally in the middle column and layer, the model was 375 ft long, 241 ft wide, and 23.5 ft thick. Two simulation runs were conducted to investigate the effect of a PPG treatment on waterflood recovery:

1) Base case, comprised of 3 PV of water injection only
2) PPG, comprised of 1 PV of pre-treatment water injection, 1 PV of PPG suspension injection, and 1 PV of post-treatment water injection

For both cases, the injection rates were maintained at 3000 ft^3/day at all time while the production rates were controlled by bottomhole pressure constraint of 200 psi. The simulation input parameters for the Conduit case I study are given in Table 5-3. The complete input data is given in Appendix B-1. The impact of having the conduit in the reservoir model was quantified and summarized in Appendix B-3.

Conduit case II

A long lateral conduit was placed in the middle of the numerical model with one injection well in the middle of the conduit and 4 production wells on four sides (Figure 5-6). The conduit was positioned to align with two out of four producers and the injection well. Note that the matrix grid was made transparent in the figure to display the conduit which was located within the reservoir model. Including the conduit, which was placed explicitly by adding 1-ft layers vertically and horizontally in the middle column and layer, the model was 627 ft long, 625 ft wide, and 19 ft thick. Again, two simulations were conducted to investigate the impact of a PPG treatment on oil recovery:

1) Waterflood, comprised of 3 PVs of water injection
2) PPG, comprised of 0.5 PV of pre-treatment water injection, 1 PV of PPG suspension injection, and 1.5 PVs of post-treatment water injection

For both cases, the injection rates were maintained at 5000 ft^3/day at all time while the production rates of all 4 wells were controlled by the bottomhole pressure constraint of 500 psi. The input parameters for case II are given in Table 5-4. The complete input data can be found in Appendix B-2. The impact of having the conduit in the reservoir model was also summarized in Appendix B-3.

Remark

It is worth pointing out that, with limited time and capability of the conventional grid simulation used in this study, the size and the permeability contrast between matrix and conduit in both cases had to be compromised; i.e., the thickness contrast between matrix and conduit aperture was around 20 ft / 1 ft in this study whereas it could be a more realistic ratio of 20 ft / 0.01 ft The permeability contrast was assumed to be 50 mD / 10,000 mD whereas the ratio of 1 mD / 1,000,000 mD is more realistic.

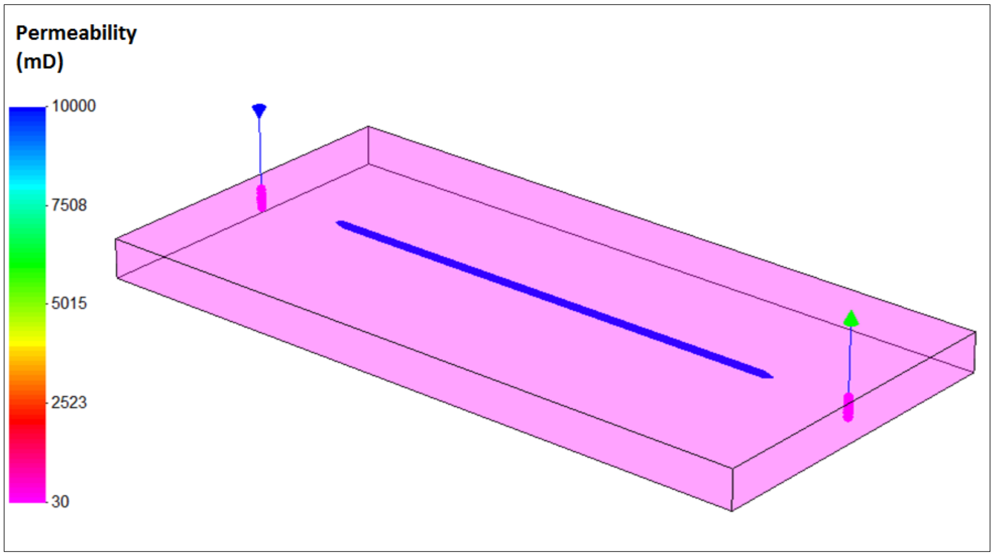


Figure 5 - 5. "Conduit case I" synthetic model

Table 5 - 3. Input parameters for "Conduit case I" synthetic model

Model	3-Dimentional Cartesian
Number of gridblocks	25 x 25 x 10
Δx, Δy, Δz	15, 10, 2.5 ft
Conduit size	285 x 1 x 1 ft
Porosity	0.3 (matrix), 0.9 (conduit)
Permeability*	50 mD (avg), 10000 mD (conduit)
Ratio of Kv/Kh	0.1
Initial reservoir pressure	2000 psi
Initial water saturation	0.31
Residual oil saturation	0.22
OOIP	78.3 MSTB
Oil viscosity	37 cp
Water viscosity	1 cp
Total injection period	3 PV
Injection PPG concentration	800 ppm
PPG particle diameter size	0.1 mm

*Note: the permeability of each grid was assigned slightly differently to reflect some degrees of heterogeneity in matrix. However, they all represented a single layer reservoir with the average permeability of 50 mD, see Appendix B-1.

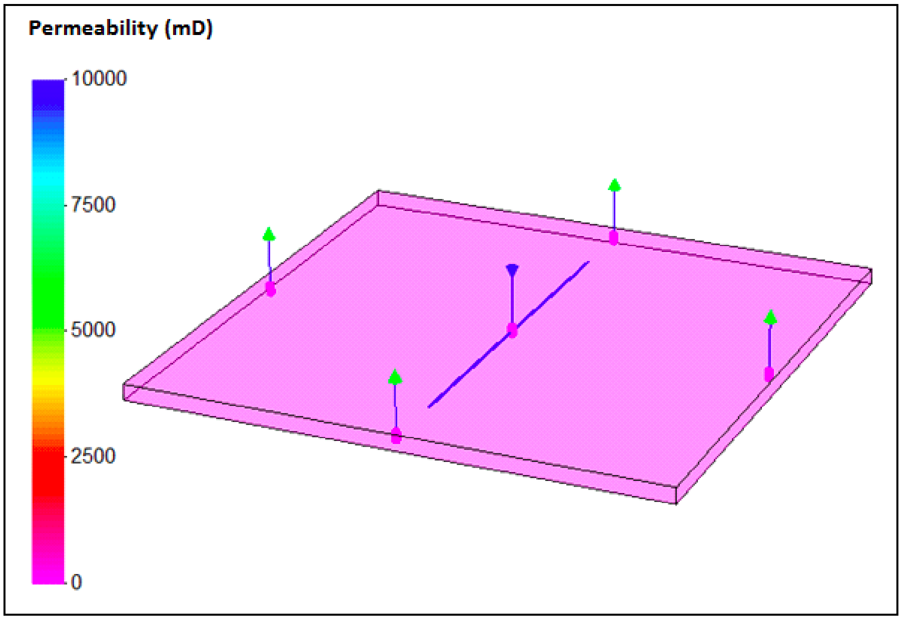


Figure 5 - 6. "Conduit case II" synthetic model

Table 5 - 4. Input parameters for "Conduit case II" synthetic model

Model	3-Dimentional Cartesian
Number of gridblocks	25 x 25 x 10
Δx, Δy, Δz	25, 28, 2 ft
Conduit size	475 x 1 x 1 ft
Porosity	0.3 (matrix), 0.9 (conduit)
Permeability*	50 mD (avg), 10000 mD (conduit)
Ratio of Kv/Kh	0.1
Initial reservoir pressure	2000 psi
Initial water saturation	0.31
Residual oil saturation	0.22
OOIP	274.6 MSTB
Oil viscosity	37 cp
Water viscosity	1 cp
Total injection period	3 PV
Injection PPG concentration	1500 ppm
PPG particle diameter size	0.1 mm

*Note: the permeability of each grid is different to reflect heterogeneous matrix. However, they all represented as a single layer reservoir with an average permeability of 50 mD. Refer to Appendix B-2 for more details.

Simulation Results:

Conduit case I

Figure 5-7 shows the oil recoveries for the waterflood and the PPG treatment in Conduit case I simulation study. According to the simulation results, the PPG treatment case resulted in an oil recovery 5.9% higher than waterflood. The waterflood oil recovery was 47.9% while that for PPG was 53.8%. The incremental recovery was attributed to the water cut reduction in the PPG case, as seen in Figure 5-8. PPG suspension was injected after 1 PV of waterflood. However, the water cut reduction response did not occur until after 0.7 PV injected. The maximum water cut reduction was approximately 7% at the time of 1.8 PV injected. After that, the water cut gradually increased and eventually was almost equal to that of the waterflood base case. It can be observed that the water breakthrough time of the pre-treatment waterflood was right after the start of injection (less than 0.1 PV injected) and the 90% water cut was reached after 1 PV of water injected with roughly 37% oil recovered. This meant that the injected water did sweep some portions or other layers but because of the thin layer in the middle containing a large conduit, there existed a small pathway where the water could reach the producer much faster and that results in a minor detriment to the waterflood recovery, see Appendix B-3.

Figure 5-9 illustrates the PPG concentration and water saturation in the layer with the lateral conduit:

- The first output time selected was at t = 0.1 PV injected, right after water had been introduced into the reservoir. No PPG had been injected yet. It can be seen that the water saturation of 0.7 had already reached the producer and that the high water saturation happened only around the injection point and the conduit as expected.
- The second output time selected was at t = 1.5 PV injected, that is after half of the PPG (0.5 PV) had been injected into the reservoir. Observe the PPG concentration in the zoomed-in figure of the PPG concentration at this output time; the PPG concentration in the narrow gridblocks of conduit was higher than that of the

surrounding matrix gridblocks. Note that as the conduit did not connect directly to the injection well in this case, the PPG selected had to be small or weak enough to be able to pass through the matrix first. Therefore, the PPG treatment did not impact only the conduit in this case but also the matrix as well. However, as the total concentration of PPG injected was 750 ppm, it can be observed that the concentrations of PPG in the conduit gridblocks were mostly close to 750 ppm, higher than the surrounding matrix gridblocks, and that the propagation of the PPG in the conduit was further beyond those in the matrix toward the producer. As for the water saturation, the injected water had been diverted to the neighboring area now that PPG had reduced the permeability of the conduit. As shown in Figure 5-10, the resistance factor or the permeability reduction factor was 1500 in the conduit gridblocks at output time t = 1.5 PV.

- The last output time selected was at t = 3 PV injected, that is the final PV injected after 1 PV of water, 1 PV of PPG suspension, and 1 PV of water had been injected. PPG in the conduit was mostly replaced by the post-treatment water injection. There were PPG remained in matrix gridblocks. This was due to the fact that the selected PPG size, small enough to pass through the matrix pore throat, was small enough to be washed out from the conduit. The water saturation profile showed that the water had displaced more oil areally at this time. Bear in mind what shown here is only one thin layer of the total reservoir. The conformance control by PPG should also happen vertically.

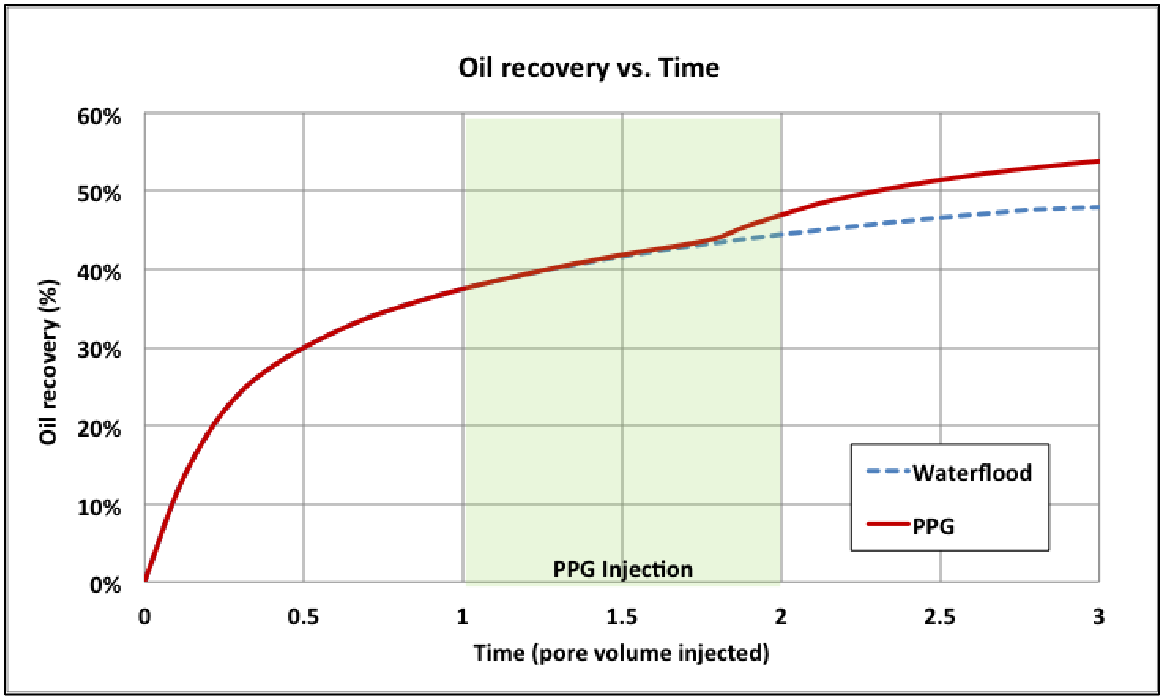


Figure 5 - 7. Oil recovery vs. time, Conduit case I

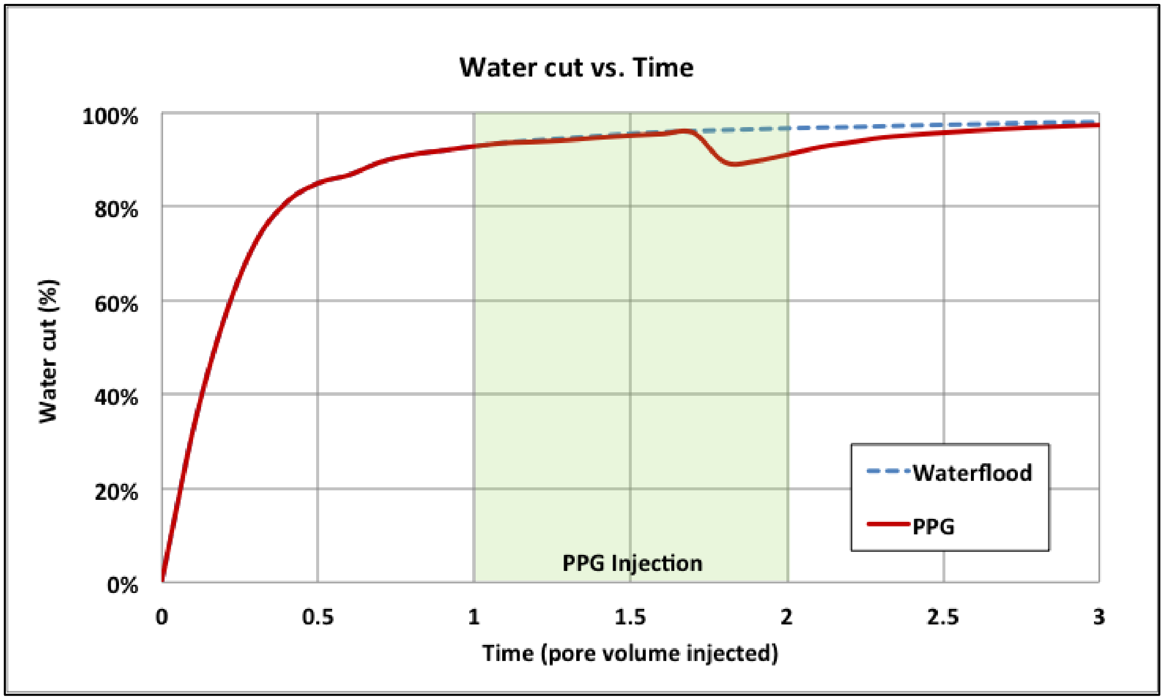
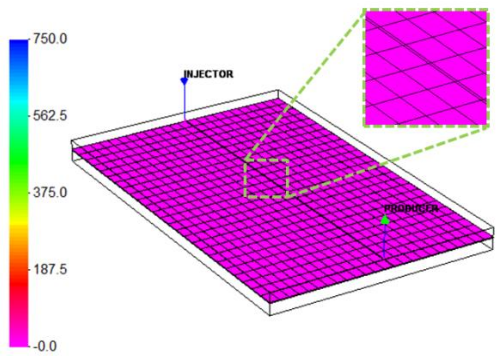
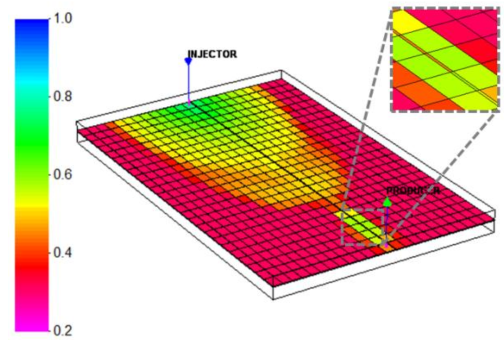
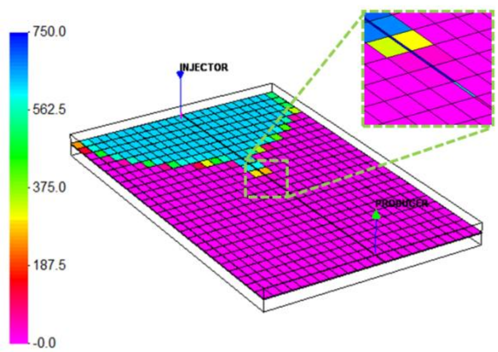
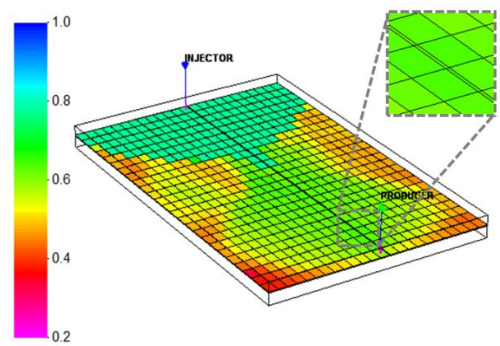
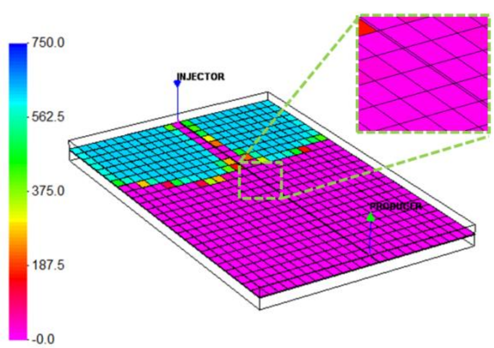
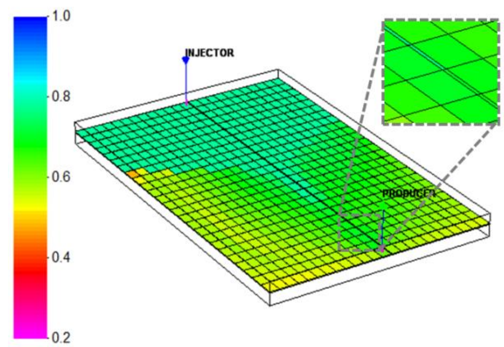


Figure 5 - 8. Water cut vs. time, Conduit case I

Figure 5 - 9. PPG concentration and water saturation in the middle layer containing the conduit at selected output times, Conduit case I

<table>
<tr><th>Output Time</th><th>PPG Concentration (ppm)</th><th>Water Saturation</th></tr>
<tr><td>t = 0.1 PV
After 0.1 PV of water injection</td><td>
</td><td>
</td></tr>
<tr><td>t = 1.5 PV
After 0.5 PV of PPG injection</td><td>
</td><td>
</td></tr>
<tr><td>t = 3 PV
Final time</td><td>
</td><td>
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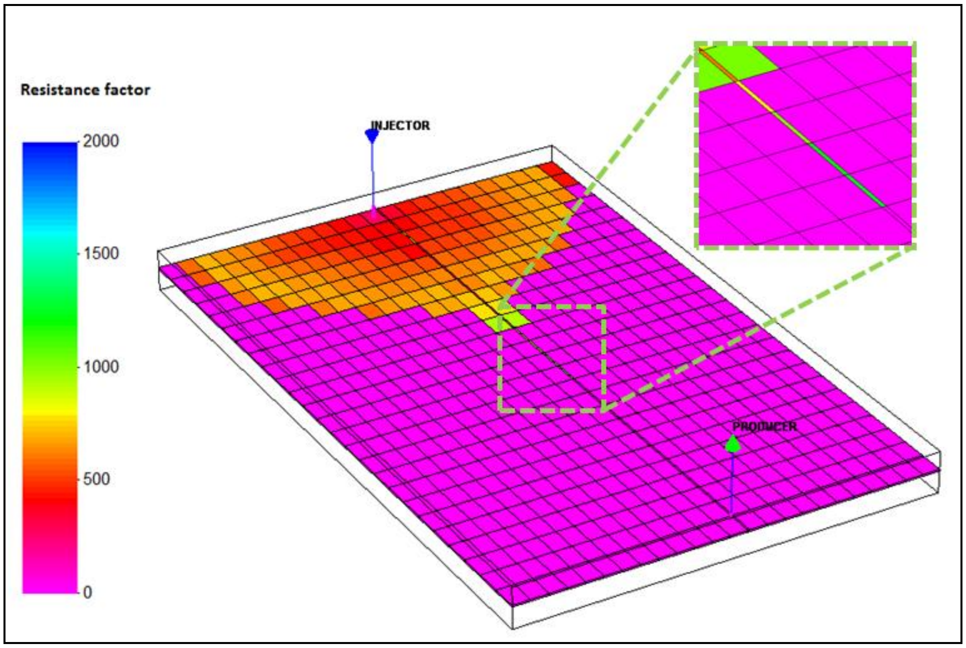


Figure 5 - 10. Resistance factor in the middle layer containing the conduit at t = 1.5 PV, Conduit case I

Conduit case II

Figure 5-11 compares oil recoveries from the waterflood and PPG treatment for the Conduit case II. According to the simulation results, the PPG treatment could increase the oil recovery by 3.3%. The oil recovery for the waterflood was 40.8% while the oil recovery from the PPG treatment with 1 PV of PPG injection was 44.1%. The incremental recovery was attributed to the water cut reduction as can be observed in Figure 5-12. The maximum water cut reduction was 3.2% from commingled producers. It is worth pointing out that the impact of PPG might seem smaller than that of the previous case despite the waterflood pattern setup and the early injection of PPG. This was owing to the larger size of the reservoir (more than three times larger) while the conduit remained the same. The reservoir could be considered nearly homogeneous. The effect of PPG in the case was, therefore, minimal. Nevertheless, the main purpose of simulating the Conduit case II was rather to observe the application of the PPG treatment with a scenario where a conduit was intentionally placed to undermine the waterflood areal sweep efficiency.

Figure 5-13 demonstrates the PPG and water saturation profiles in the layer containing the conduit:

- The first output time was at t = 0.1 PV injected, that is right after water had been injected. It can be seen that the injected water traveled straight to the two producers that were aligned with the conduit. The water saturations at these two production wells were approximately 0.5 while those of the other two producers were still at the initial water saturation of 0.31.
- The second output time was at t = 1.0 PV injected, that is after half of the PPG suspension (0.5 PV) had been injected. As can be observed in the zoomed-in figure of the PPG concentration at this output time; the PPG concentration in the conduit was higher than that of the surrounding matrix. Again, the PPG treatment did not impact only the conduit but also the matrix as well. It can be observed that the concentrations of PPG in the conduit gridblocks were mostly close to injection PPG concentration of

1500 ppm. The propagation of the PPG in the conduit was further beyond those in the matrix toward the two producers in alignment with the conduit. As for the water saturation, the injected water had swept more neighboring area. This was because the permeability of the conduit had been reduced greatly by PPG. As shown in Figure 5-14, the resistance factor or the permeability reduction factor was as high as 7500 in the conduit gridblocks at output time t = 1.0 PV.

- The last output time was at t = 3 PVs injected (1 PV of water, 1 PV of PPG suspension, and 1 PV of water). As can be seen in the zoomed-in figure, PPG in the conduit was mostly replaced by the post-treatment water injection. There were some PPG remained in matrix gridblocks. This was due to the fact that the selected PPG size was small enough to be washed out from the conduit. The water saturation profile showed that the water had displaced more oil areally at this time. Again, it is worth pointing out that what shown here is only from one layer. The conformance control by PPG should impact the vertical sweep efficiency as well.

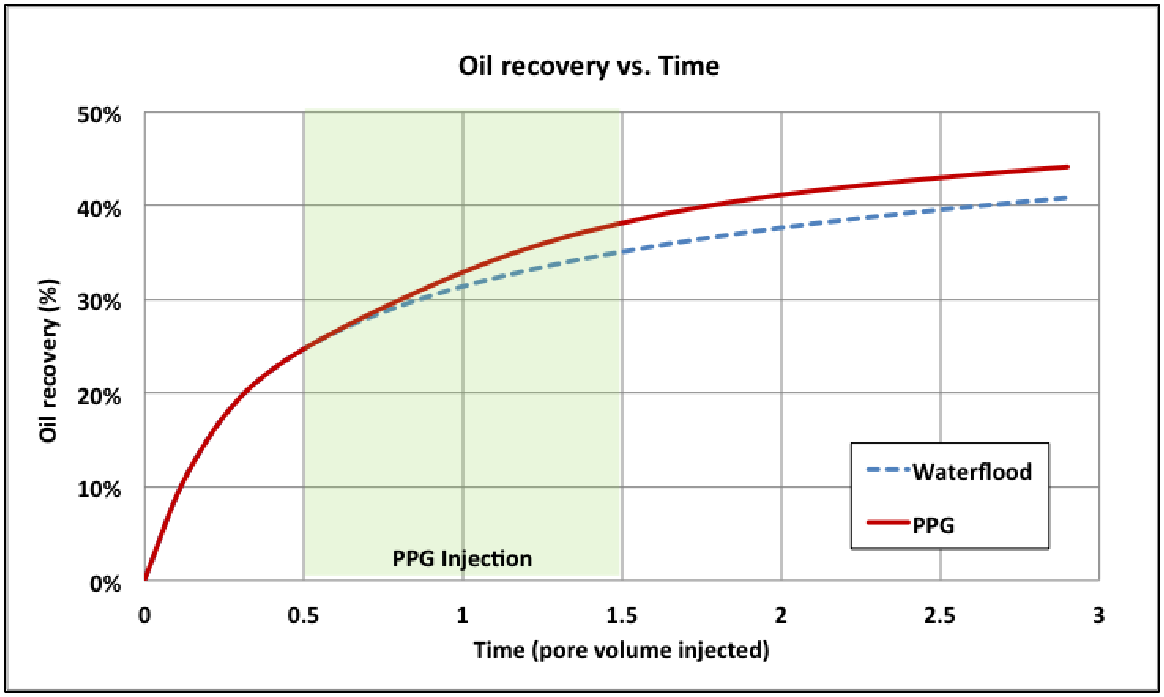


Figure 5 - 11. Oil recovery vs. time, Conduit case II

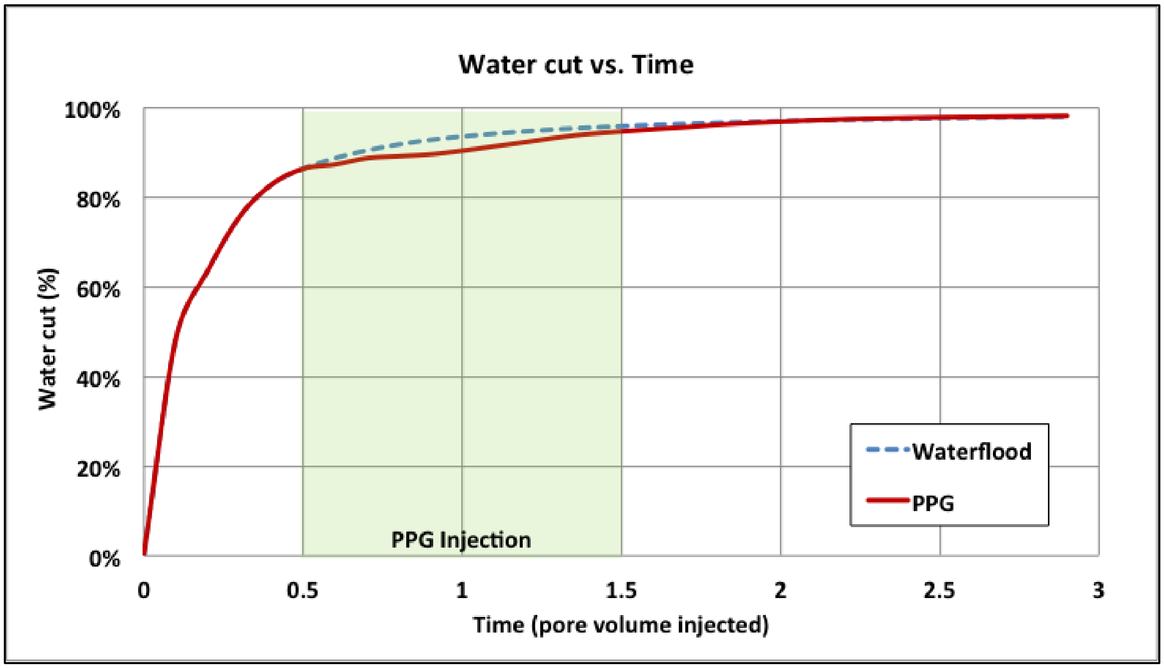
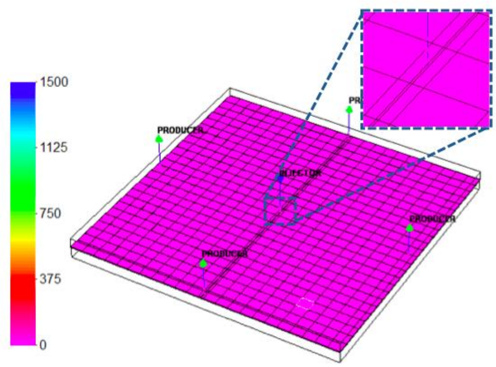
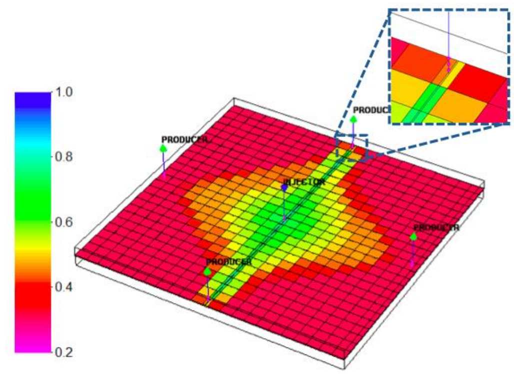
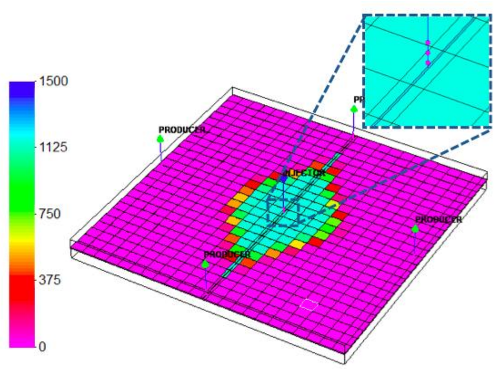
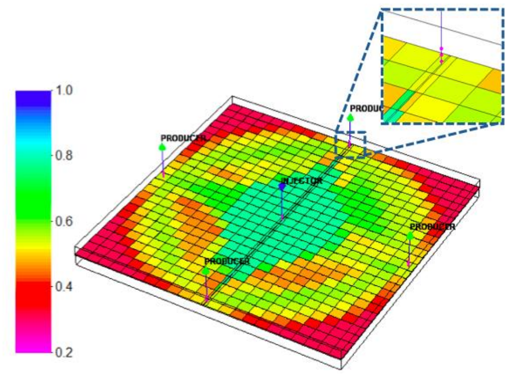
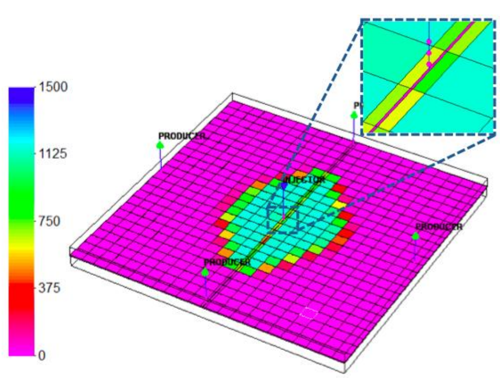
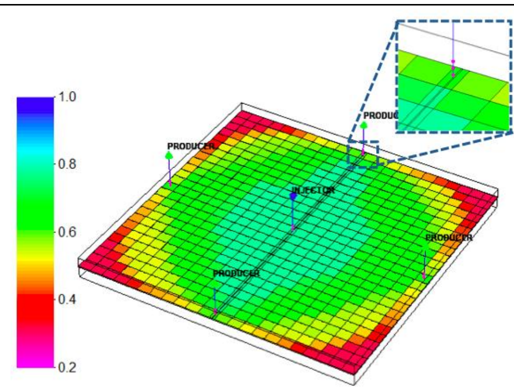


Figure 5 - 12. Water cut vs. time, Conduit case II

Figure 5 - 13. PPG concentration and water saturation in the middle layer containing the conduit at selected output times, Conduit case II

Output Time	PPG Concentration (ppm)	Water Saturation
t = 0.1 PV After 0.1 PV of water injection		
t = 1 PV After 0.5 PV of PPG injection		
t = 3 PV Final time		

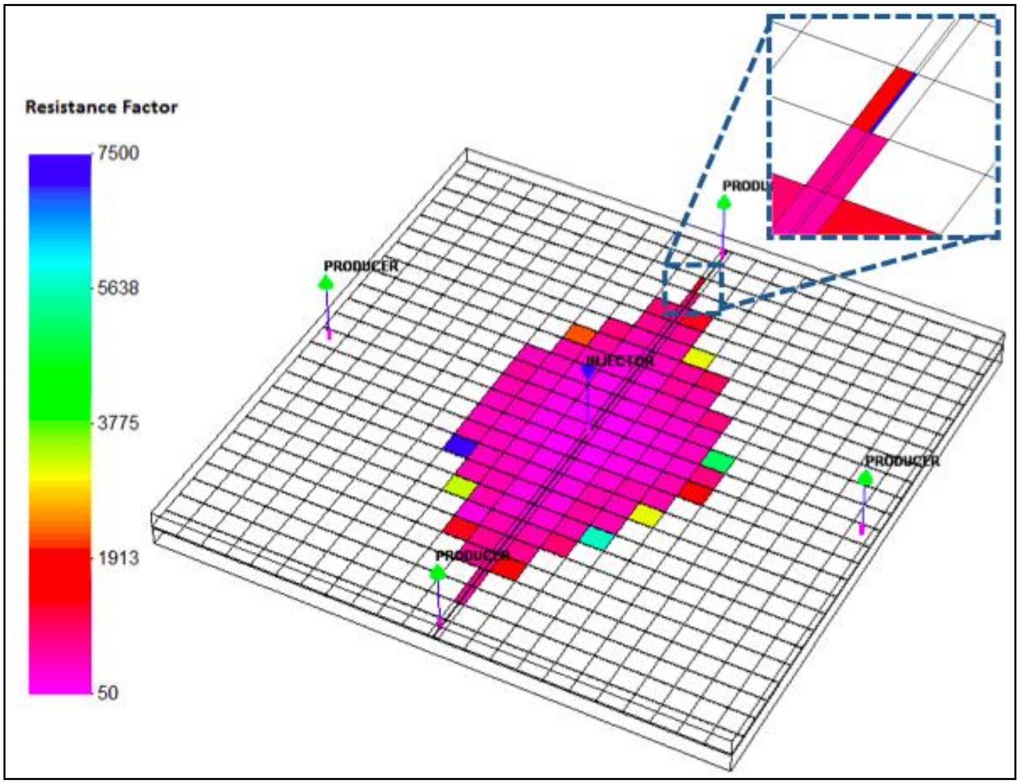


Figure 5 – 14. Resistance factor in the middle layer containing the conduit at t = 1.0 PV, Conduit case II

Summary and Conclusions:

1. For two numerical cases with conduits studied, PPG could successfully increase the waterflood oil recovery by greatly reducing the permeability of the extremely high permeability conduit. The injected water was then diverted to displace the oil the outside of the conduit. Additional oil recovery from PPG treatment was 5.9% for case I, and 3.3% for case II.
2. Both synthetic cases demonstrated that PPG treatments could improve the areal waterflood sweep efficiency in the event that a high-permeability conduit existed in the reservoir and was in the position to undermine the sweep efficiency.
3. Although not being focused in this study, timing of PPG injection, PPG concentration, and PPG size selections can play important roles in optimizing the PPG treatment.
4. There were computational time and memory limitations in modeling a representative fracture or conduit. Another approach of numerical calculation is required for a better modeling and a more effective simulation of a reservoir containing fractures or conduits. One such option will be presented in Chapter 7.

Chapter 6: Field Case Simulation

6.1. Field Case I- Gel Type Comparison

Field Case Description:

The reservoir model was obtained from an actual operating field where a significant degree of heterogeneity had been identified. It covered approximately 260 acres (983 m x 1075 m) and was 37 ft in thickness. The field consisted of 10 injection wells and 7 production wells, all of which were vertical wells with perforated completion over the entire pay zone. The permeability varied both vertically and areally from less than 10 mD to 17,000 mD. Figure 6-1 illustrates the three-dimensional reservoir model for Field case I with given permeability distribution.

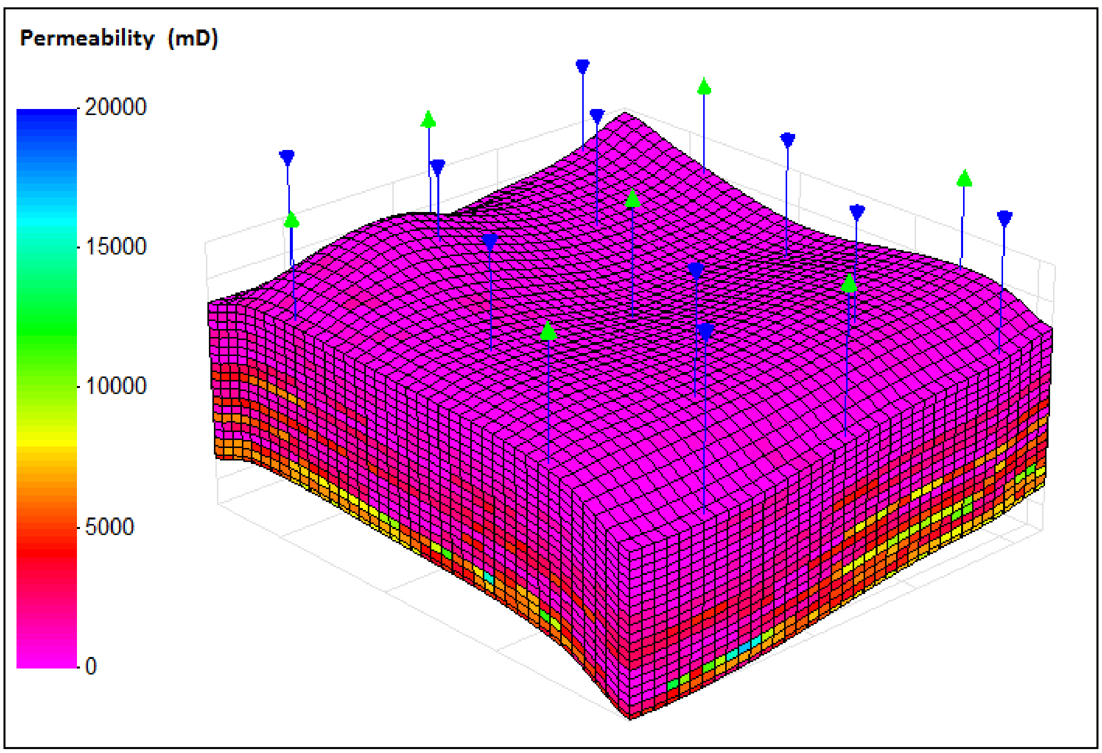


Figure 6 - 1. Reservoir model with permeability distribution, field case I

Simulation Case Study:

To divert injected water from high permeability into low permeability zones with larger remaining oil saturation, a method of conformance control using gels was therefore recommended for improving waterflood recovery. We performed reservoir simulations to investigate the performance of three different types of gels, namely; bulk gel, CDG, and PPG.

Four production scenarios were simulated:

1) Base case (waterflood), comprised of 7.3 PV of water injection
2) PPG treatment, comprised of 5.0 PV of pre-treatment water injection, 0.3 PV of PPG treatment, and 2.0 PV of post-treatment water injection
3) CDG treatment, comprised of 5.0 PV of pre-treatment water injection, 0.3 PV of CDG treatment, and 2.0 PV of post-treatment water injection
4) Bulk gel treatment, comprised of 5.0 PV of pre-treatment water injection, 0.3 PV of bulk gel treatment, and 2.0 PV of post-treatment water injection

With the same treatment concentration, injection volume, and injection rate, the performance of each gel treatment can be evaluated and compared with that of waterflood. The simulation input parameters are given in Table 6-1.

Table 6 - 1. Input parameters for field case I

Model	3-Dimentional Cartesian
Number of gridblocks	43 x 47 x 19
Δx, Δy, Δz	75, 75, 2 ft
Porosity	0.17 (avg), 0.35 (max)
Permeability	1500 mD (avg), 17000 mD (max)
Dykstra Parsons coefficient	0.64
Ratio of Kv/Kh	0.1
Initial water saturation	0.2
OOIP	10.3 MMSTB
Oil viscosity	3.4 cp
Water viscosity	0.37 cp
Temperature	72.5 °F
Production bottomhole pressure constraint	300 psi
Injection rate	Different for each well
Total injection period	7.3 PV
Injection gel concentration	2000 ppm

Simulation Results:

The water cut profile for each treatment scenario described previously is presented in Figure 6-2. It can be observed that all gel treatments resulted in the decrease in water cut for a short period of time when compared to the waterflood base case. While the reduction in water cut was different for each gel type, they were rather close to each other, in a range of 30-40% at peaks after the gel injection. This led to incremental oil recoveries of approximately 8-12% from all treatments when compared to the base case of water injection alone. The incremental oil recovery from each treatment scenario is shown in Figure 6-3.

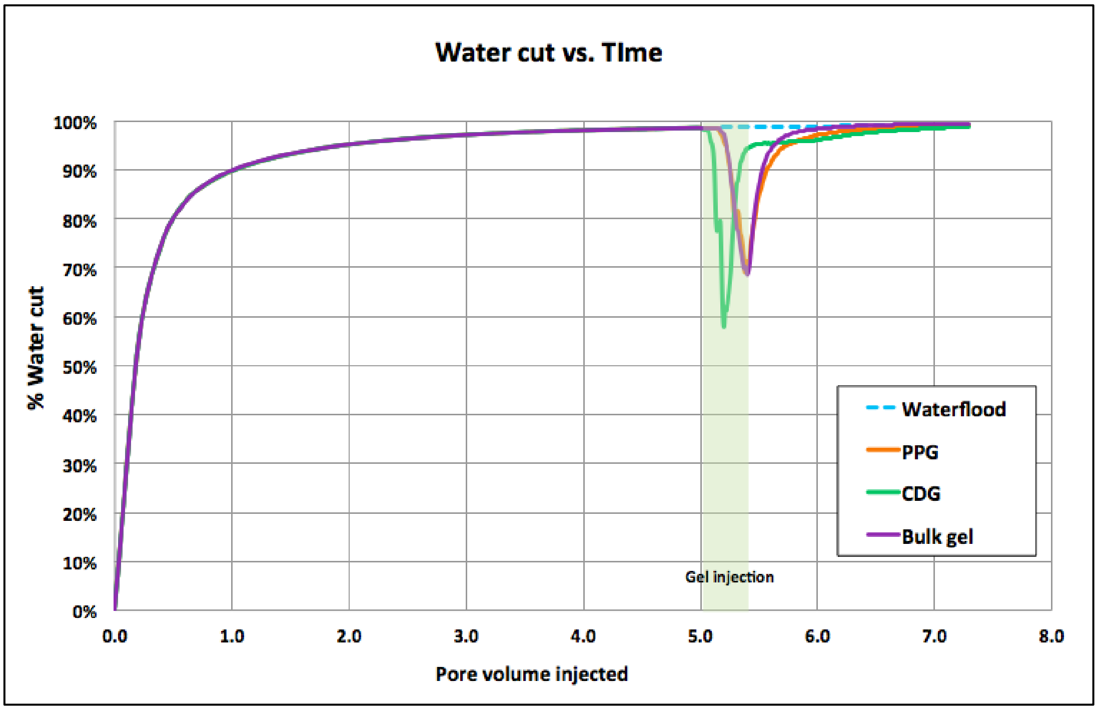


Figure 6 - 2. Water cut vs. time, field case I

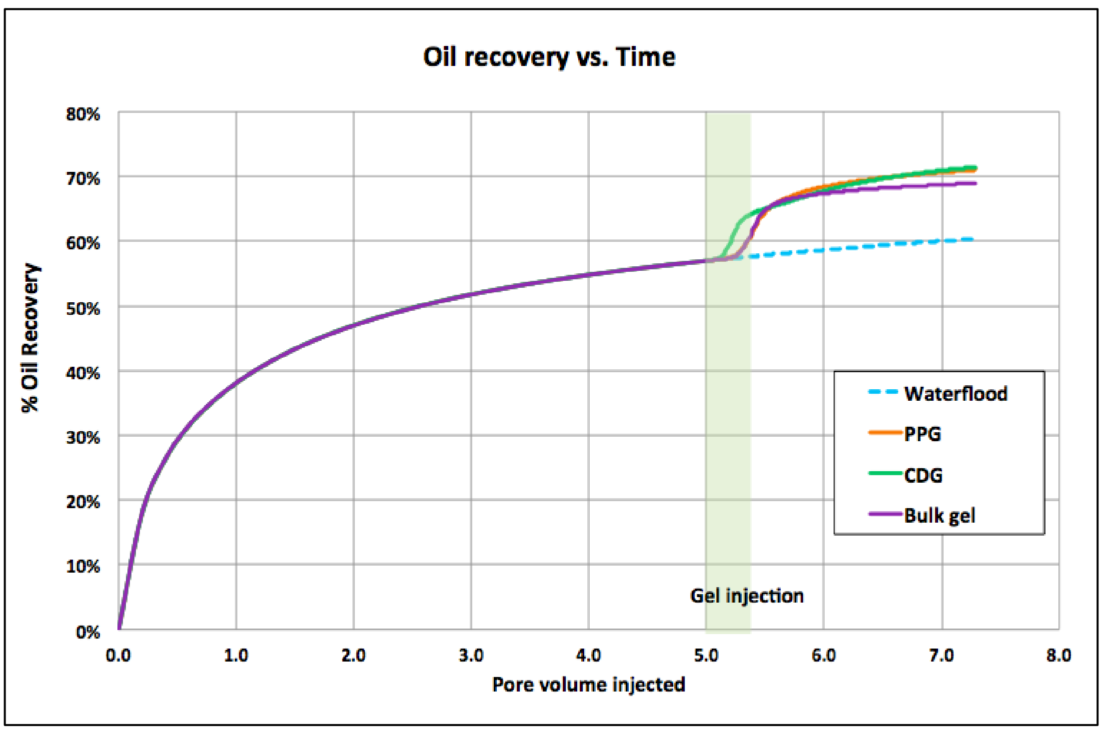


Figure 6 - 3. Oil recovery vs. time, field case I

Figure 6-4 demonstrates the total recovery from each scenario. Three gel treatments clearly improved the oil recovery where CDG treatment gave slightly higher incremental recovery compared to PPG followed by bulk gel. The recoveries are similar and about 10% higher than the waterflood.

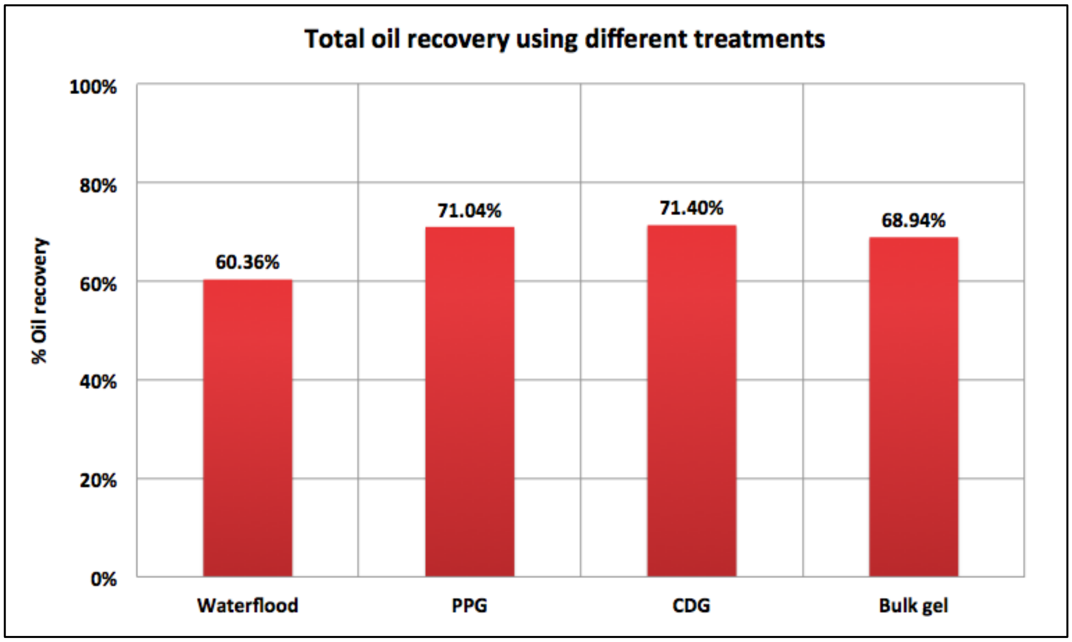


Figure 6 - 4. Comparison of total oil recovery from each scenario, field case I

Summary and Conclusions:

Three types of gels were successfully simulated using UTGEL with actual field data. The outcomes of this simulation study implied the applicable use of these three gels in improving waterflood performance in a field scale. In addition, with the simulation results indicating rather similar incremental oil recovery using the three gels; this suggested a level of validity between different gel modules used in UTGEL (i.e. PPG, CDG, and bulk gel modules). Further optimization study including operational, cost, and logistics could be conducted for each gel type in order to select the most suitable treatment for a given field.

6.2. Field case II – PPG Concentration Optimization

Field Case Description:

Modified from an actual operating field where a study was conducted for an ASP pilot project, the reservoir was selected for this simulation study of improving waterflood performance by PPG treatment. The modeled field covered approximately 9 acres (19 m x 19 m), with 40 ft in thickness. The field consisted of 4 injection wells and 9 production wells, all of which were vertical wells with perforated completion across the entire reservoir thickness. Illustrated in Figures 6-5 and 6-6 are three-dimensional up-scaled reservoir model with a distribution of permeability and initial water saturation, respectively. The permeability varied between 800 mD to 2,500 mD, with the Dykstra Parsons coefficient of about 0.46. Figure 6-5 indicates that the middle layer is the most permeable layer.

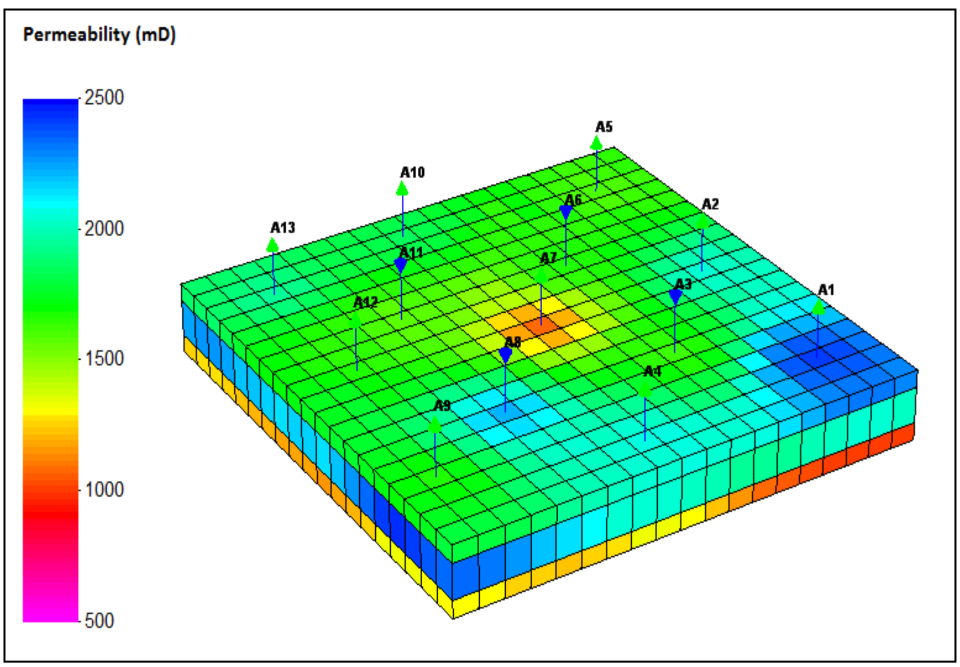


Figure 6 - 5. Simulation grids with permeability distribution, field case II

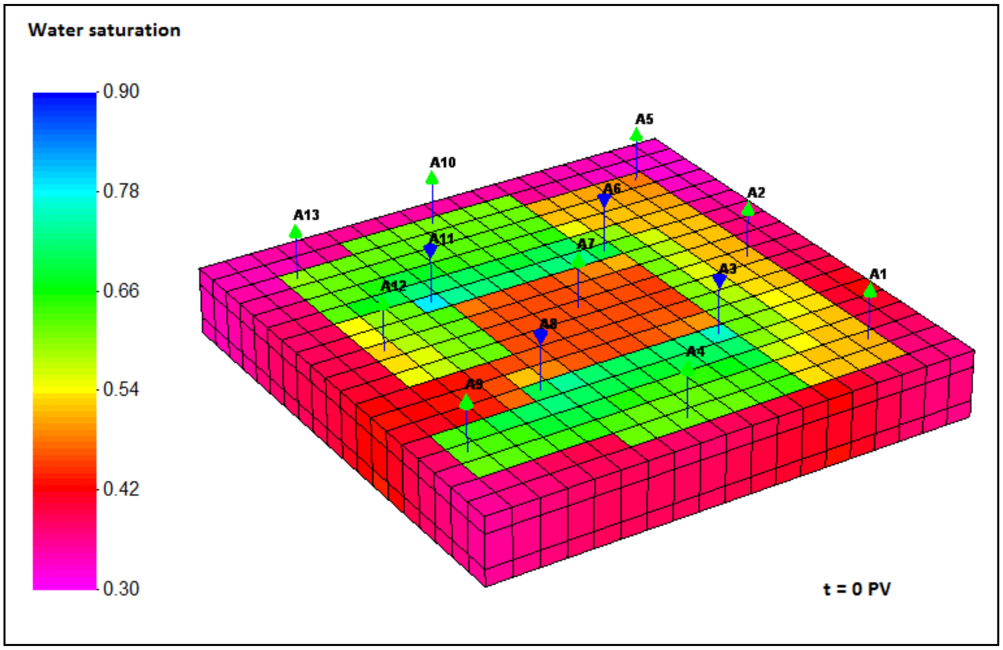


Figure 6 - 6. Simulation grids with water saturation distribution, field case II

Simulation Case Study:

The objective of this study was primarily to investigate the effect of PPG concentration on its performance. We performed a number of simulations to simulate the waterflood performance compared to PPG treatments using different PPG concentrations; five scenarios were investigated:

1) Base case (waterflood), comprised of 1,000 days (or 1.8 PV) of water injection
2) Four PPG cases with four different PPG concentration; 500, 1000, 2000, and 4000 ppm, comprised of 100 days of pre-treatment water injection, 300 days of PPG injection (with different PPG concentration for each case), and 600 days of post-treatment water injection

The input parameters are given in Table 6-2. All parameters were the same except the concentration of PPG. Sensitivity analysis was conducted to optimize the incremental oil recovery from PPG treatment while taking into consideration the increase in maximum injection pressure required with the increase in PPG concentration.

Table 6 - 2. Input parameters for field case II

Model	3-Dimentional Cartesian
Number of gridblocks	19 x 19 x 3
Δx, Δy	32.8 ft
Δz	10, 20, 10 ft
Porosity	0.3
Permeability	1655 mD (avg), 2457 mD (max)
Dykstra Parsons coefficient	0.46
Ratio of Kv/Kh	0.1
OOIP	405 MSTB
Oil viscosity	40 cp
Water viscosity	0.46 cp
Total injection period	1000 days (1.8 PV)
Injection PPG concentration	500, 1000, 2000, and 4000 ppm

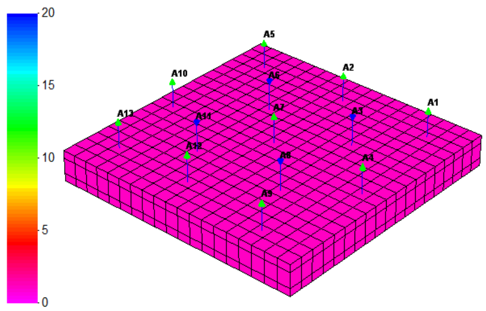
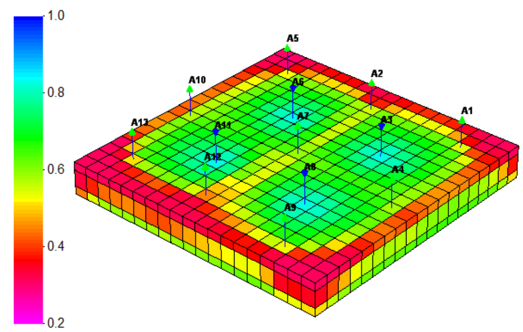
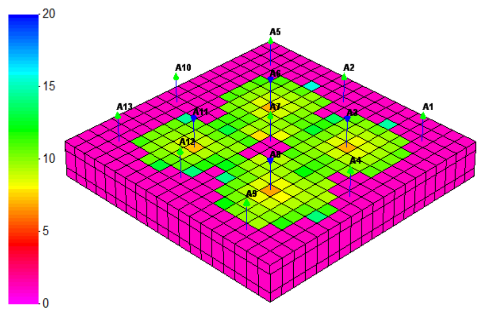
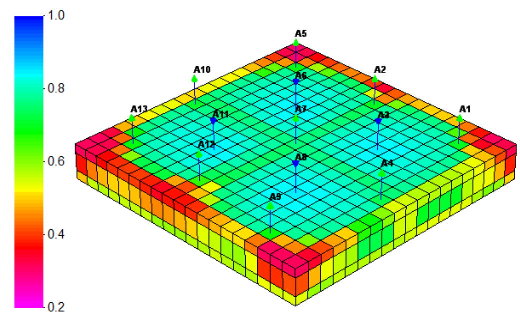
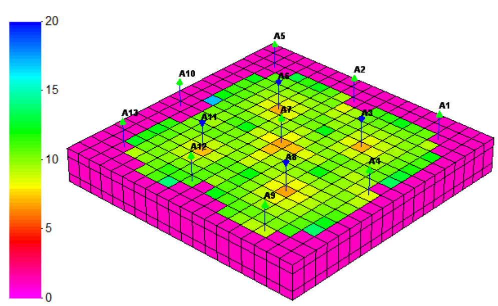
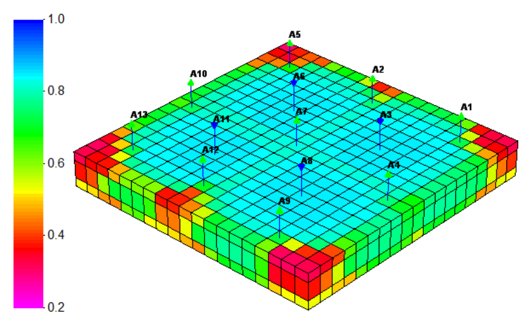
Note that the injection/production periods and rates used were obtained from the ASP pilot simulation study (Delshad, et al., 1998), see Appendix C-2 for complete input data

Simulation Results:

Figure 6-7 presents the permeability reduction factors obtained at the end of PPG injection (t = 400 days, PV = 0.72) and the final water saturation at the end of the treatment program i.e. after the post-treatment waterflood (t = 1000 days, PV = 1.80). Three cases; namely, waterflood (base case), PPG 1000 ppm, and PPG 4000 ppm, were selected to demonstrate permeability reduction factor due to PPG treatments, and how the subsequent water following PPG could improve sweep in both areal and vertical directions.

The plots of oil rate, water cut, and oil recovery versus PV injected are shown in Figure 6-8, 6-9, and 6-10, respectively. The results suggested that PPG treatments led to higher incremental oil recovery when the PPG concentration was increased. This can be explained by the fact that increasing in PPG concentration resulted in higher effective viscosity and higher permeability reduction factor. Figure 6-8 demonstrates the increase in oil rates during the PPG treatments while Figure 6-9 demonstrates the reduction in water cut. The maximum water cut reduction increased with PPG concentration and was as high as 25% when PPG concentration of 4000 ppm was used.

Figure 6 - 7. Permeability reduction factor obtained at the end of PPG injection period and final water saturation obtained at the end of the treatment, field case II

Production Scenario	**Permeability Reduction or Resistance Factor at t = 400 days, end of PPG injection period**	**Water Saturation at t = 1000 days, end of post-treatment waterflood**
Waterflood		
PPG 1000 ppm		
PPG 4000 ppm		

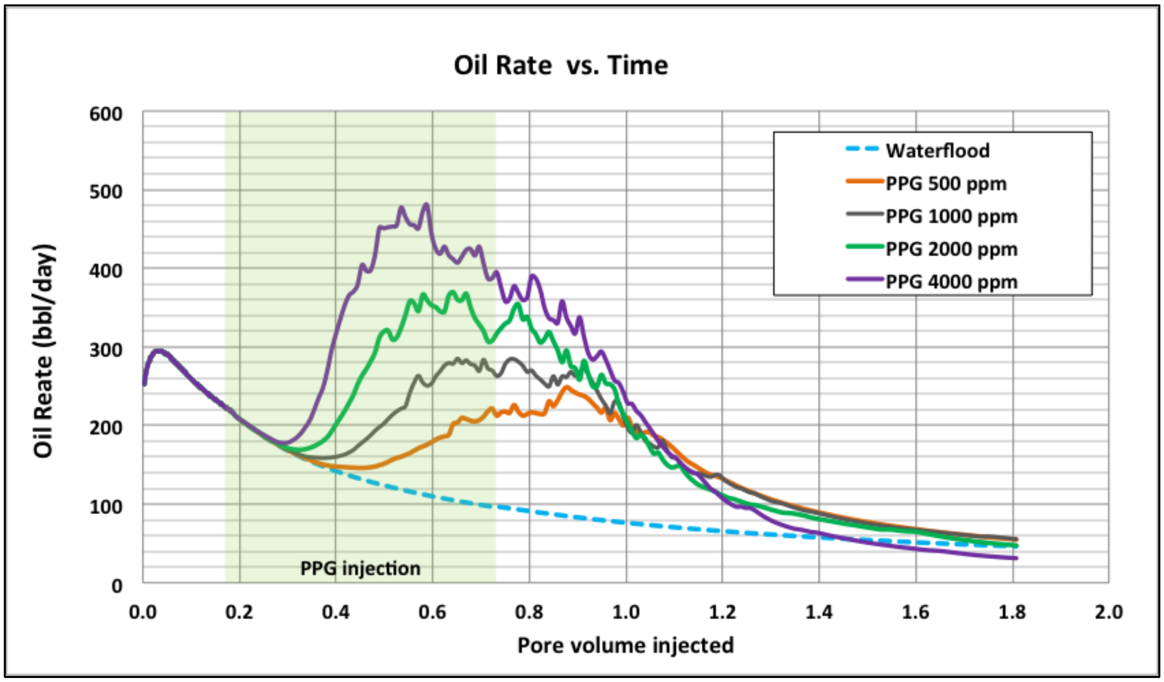


Figure 6 - 8. Oil rate vs. time, field case II

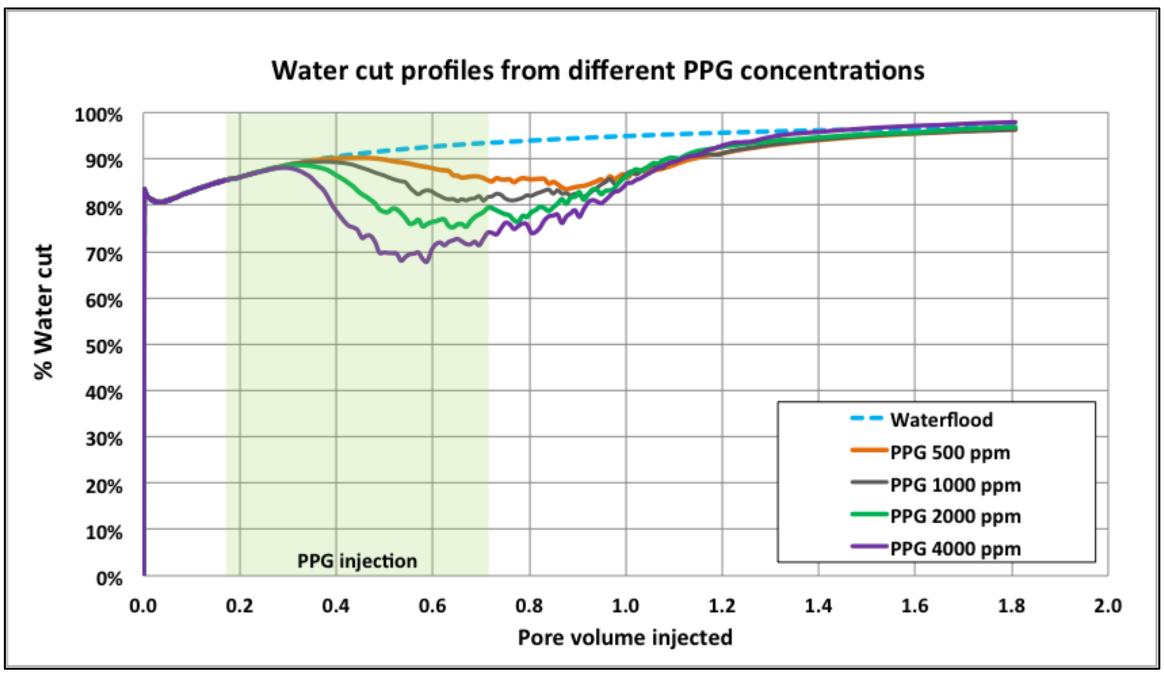


Figure 6 - 9. Water cut vs. time, field case II

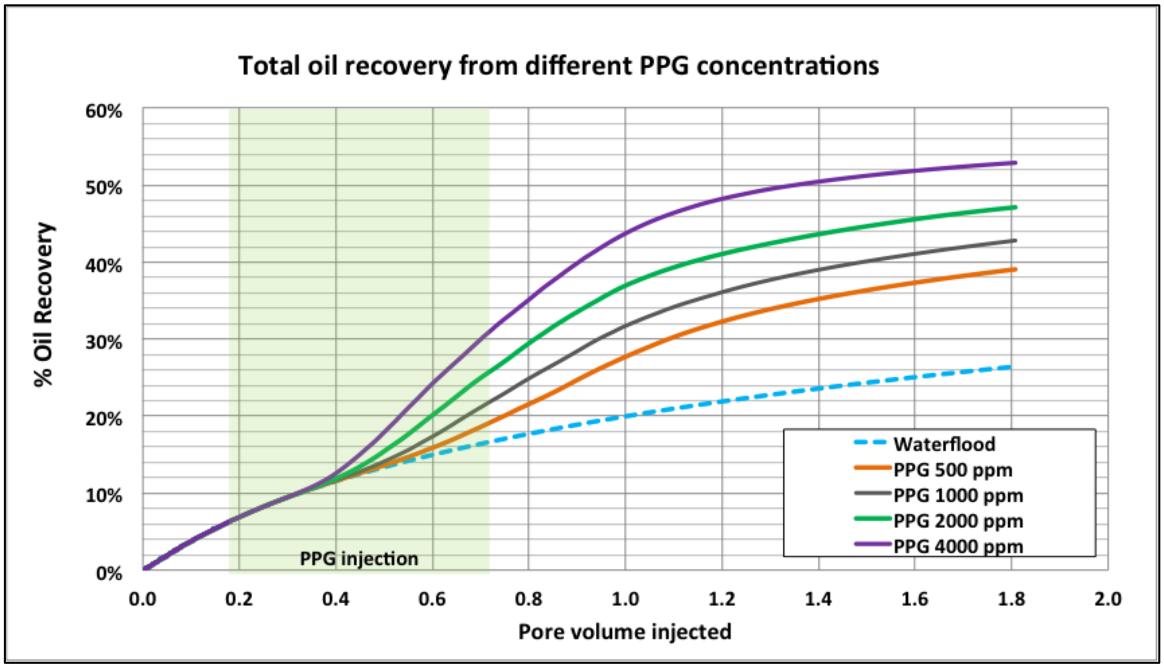


Figure 6 - 10. Oil recovery vs. time, field case II

Presented by a bar graph in Figure 6-11 is the comparison of the total oil recovery obtained from the waterflood and different PPG treatment scenarios. The plot in Figure 6-12 illustrates how the incremental oil recovery can be correlated with PPG concentrations. The correlation suggests that incremental recovery becomes sensitive to the PPG concentration beyond certain value.

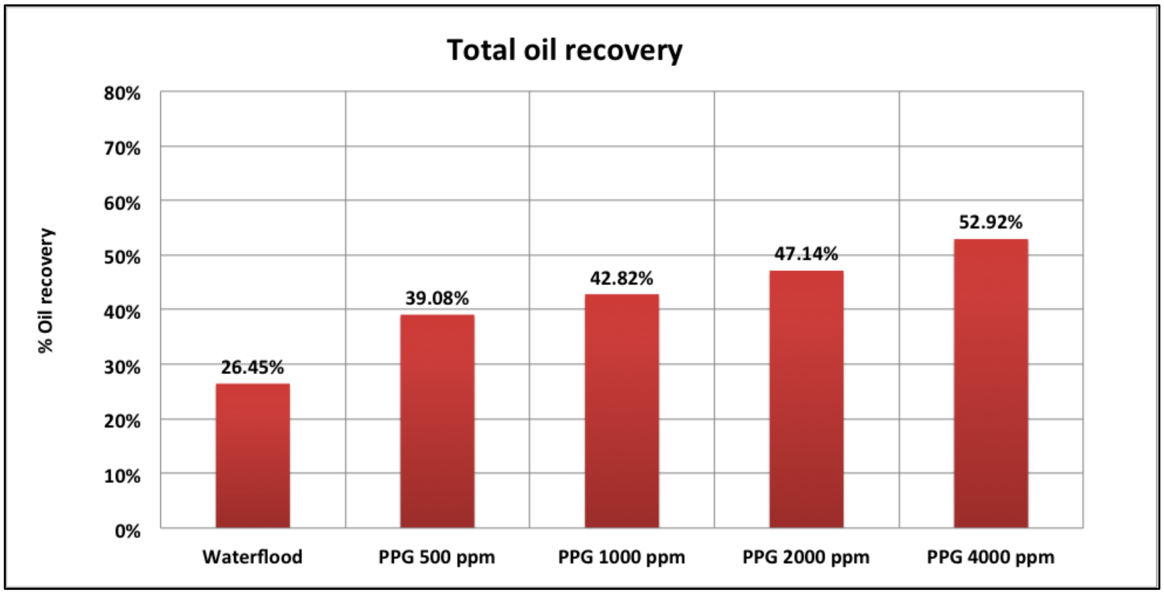


Figure 6 - 11. Comparison of oil recovery from each scenario, field case II

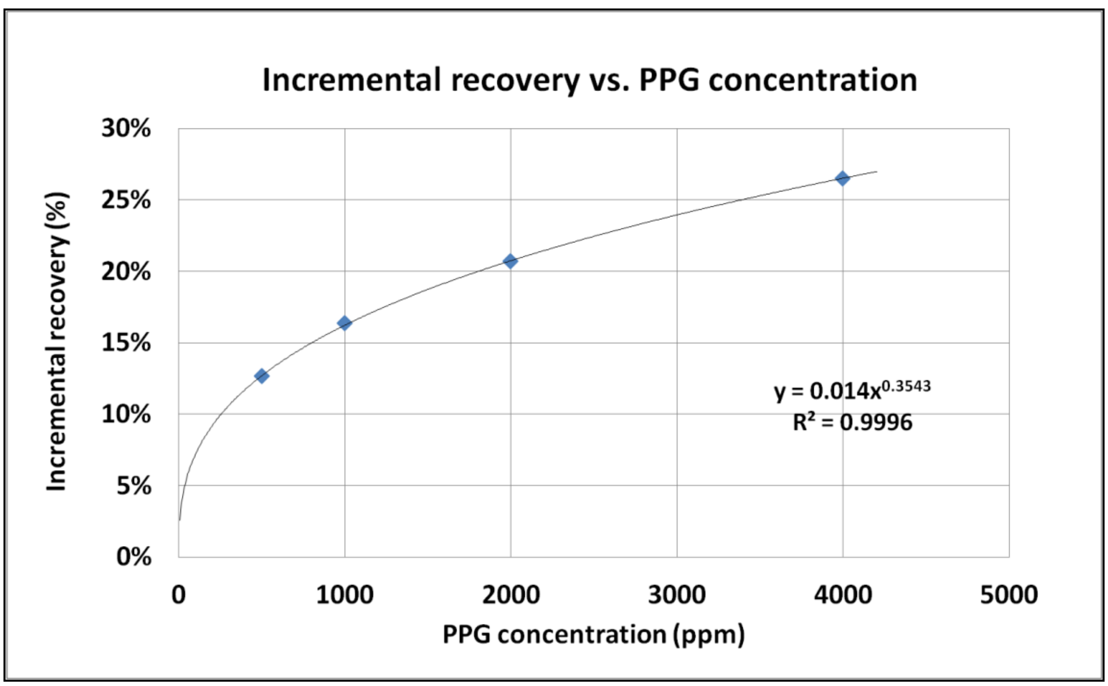


Figure 6 - 12. Correlation between incremental recovery and PPG concentration, field case II

Even though increasing PPG concentration tends to result in higher incremental oil recovery, in field design, it is recommended that the operational parameters e.g. injection pressure be roughly estimated beforehand to avoid exceeding operational limits. Figure 6-13 demonstrates the bottomhole injection pressure simulated. While the injection pressure of the waterflood was about 1800 psi, adding PPG resulted in elevated injection pressure in the range of 100-1200 psi. Presented in Figure 6-14 is the comparison of maximum injection pressure required for each scenario while Figure 6-15 shows the correlation between the PPG concentration and the maximum injection pressure required for this particular field PPG treatment. It can be observed that the correlation here is also not linear. Small increment in PPG concentration can cause a significant difference in a maximum injection pressure when the concentration is above 2000 ppm.

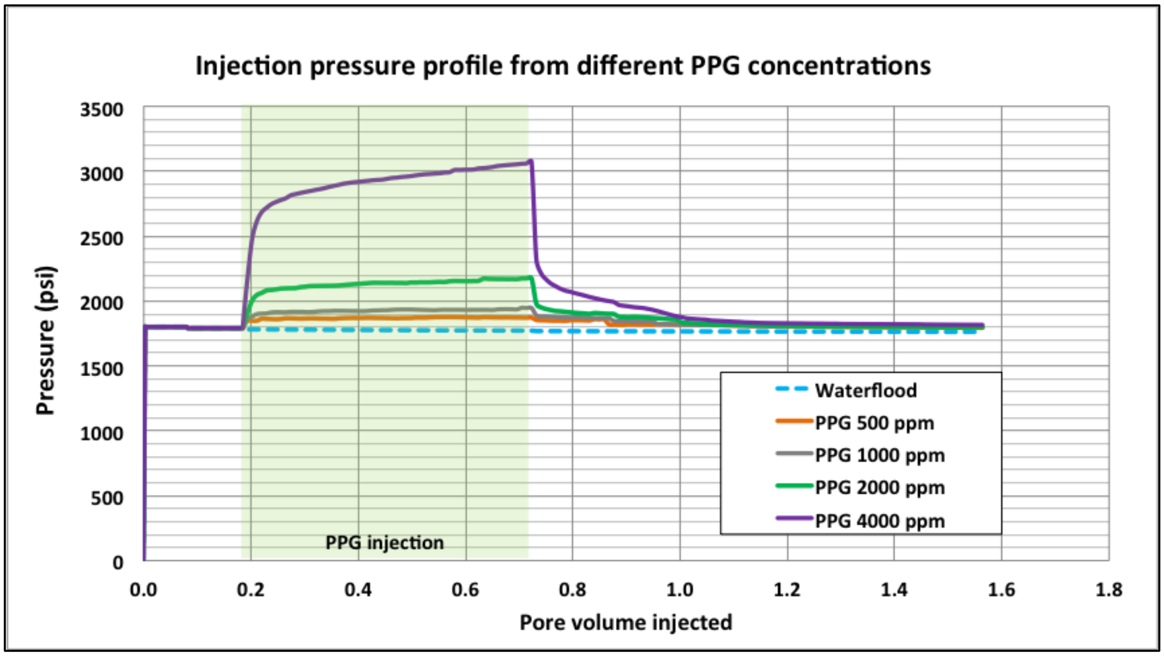


Figure 6 - 13. Injection pressure vs. time, field case II

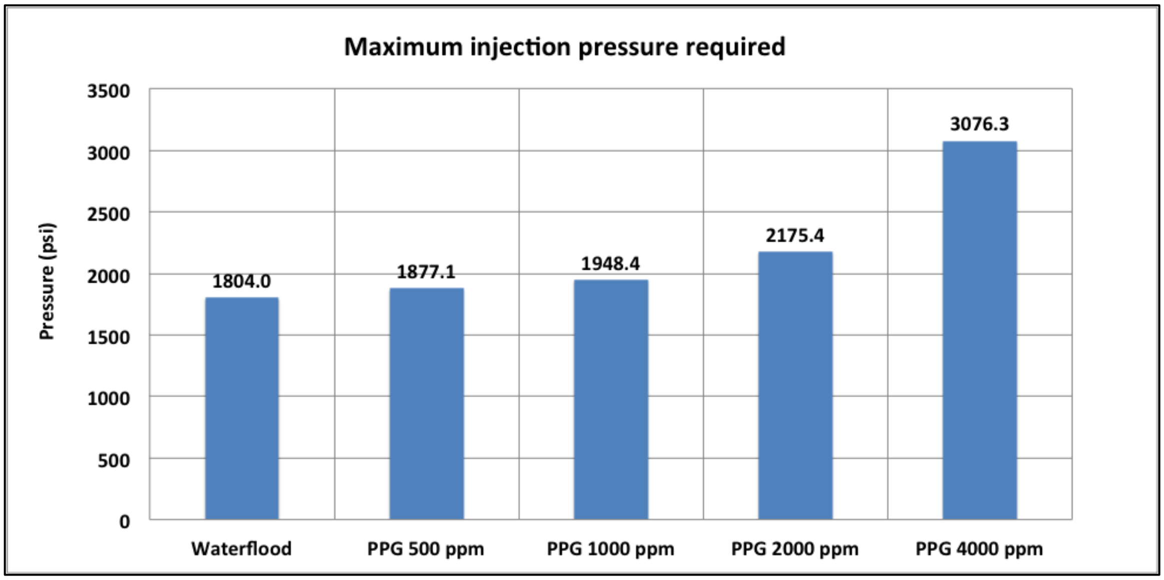


Figure 6 - 14. Comparison of maximum injection pressure for each scenario, field case II

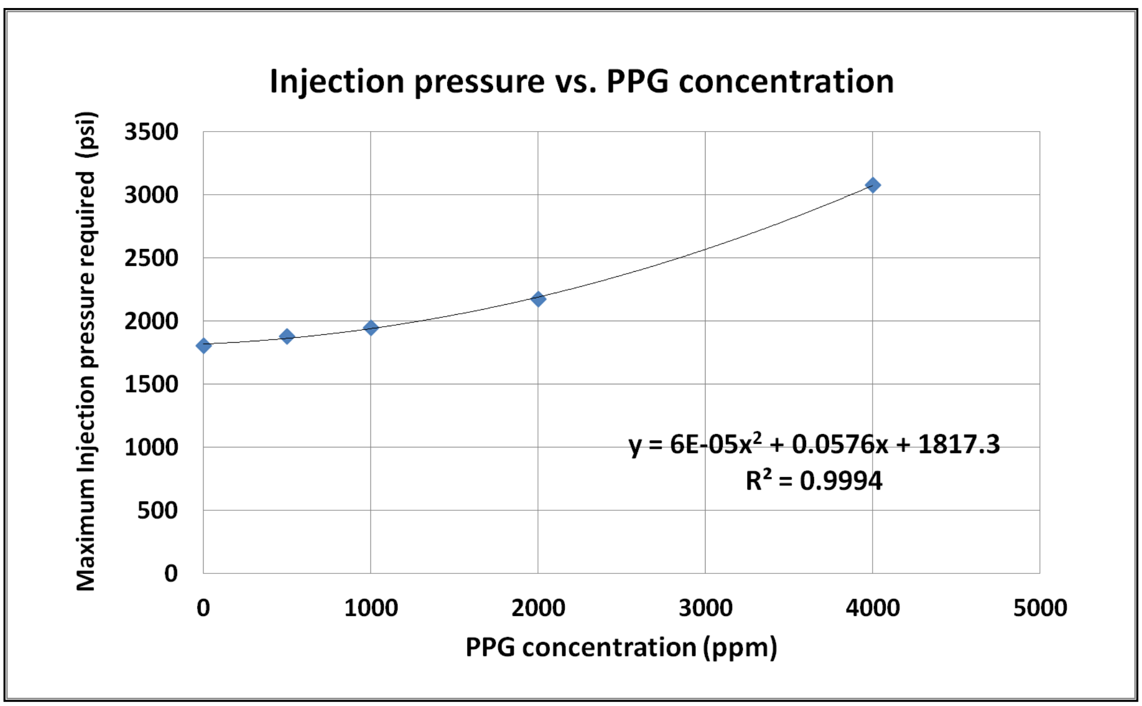


Figure 6 - 15. Correlation between maximum injection pressure and PPG concentration, field case II

Summary and Conclusions:

Simulations of PPG treatments using field data were successfully performed. Compared to the waterflood, PPG treatment could lead to an incremental oil recovery ranging from 13-25%. The incremental oil produced was a function of PPG concentration where the higher concentration of PPG contributed to greater amount of oil recovered. Nevertheless, it is important that the increase in injection pressure should be taken into consideration. The highest PPG concentration of 4,000 ppm could increase the bottomhole injection pressure to as high as 3,000 psi. This may not be in this field without fracturing the formation. For such a case, it could be worth exploring the option of injecting 2,000 ppm but doubling the period of injection in the simulation to keep the same mass of PPG injected. Moreover, while PPG treatment is often expected to increase oil recovery by diverting the injected water vertically (from high permeability to lower permeability layers), it can be observed that PPG can also improve the areal sweep effieciency.

6.3. Field case III – PPG Size Selection

Field Case Description:

Modified from an actual operating field where waterflood had been implemented with substandard performance due to early water breakthrough and poor sweep efficiency, a sector model was selected for PPG simulation study. The sector model was approximately 116 acres (607 m x 775 m), with 86 ft in thickness. The model consisted of 1 injection well and 2 production wells. Illustrated in Figures 6-16 and 6-17 are a three-dimensional up-scaled reservoir model with a distribution of permeability and initial water saturation, respectively. The permeability of the reservoir varied between 10 mD to 1,000 mD with many extra-low permeability streaks and shale barriers. The injector, drilled down-dip of the producers, was in the vicinity of the tight portion of the reservoir with permeability less than 100 mD. To achieve a good in-depth permeability reduction effect from PPG in this case, it is necessary that suitable PPG size be selected for proper propagation from the injector. Large size PPGs would not pass through the pore throat while small size PPGs would be flushed out at the producers.

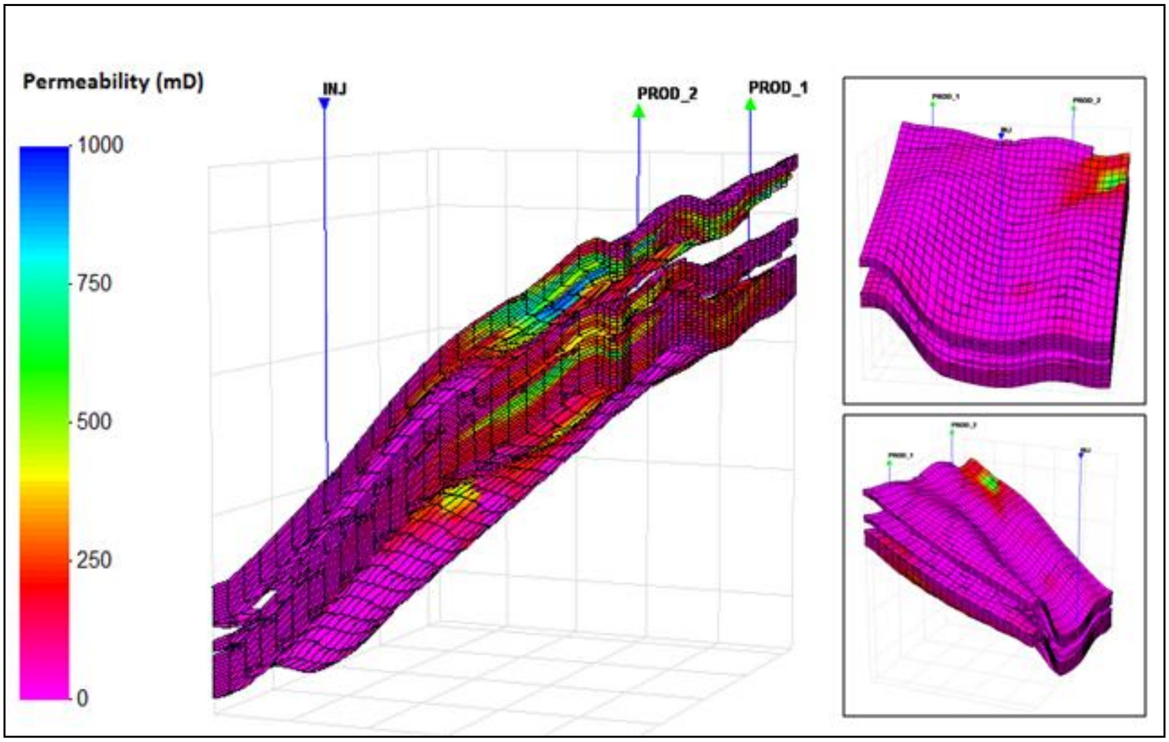


Figure 6 - 16. Simulation grids with permeability distribution, field case III

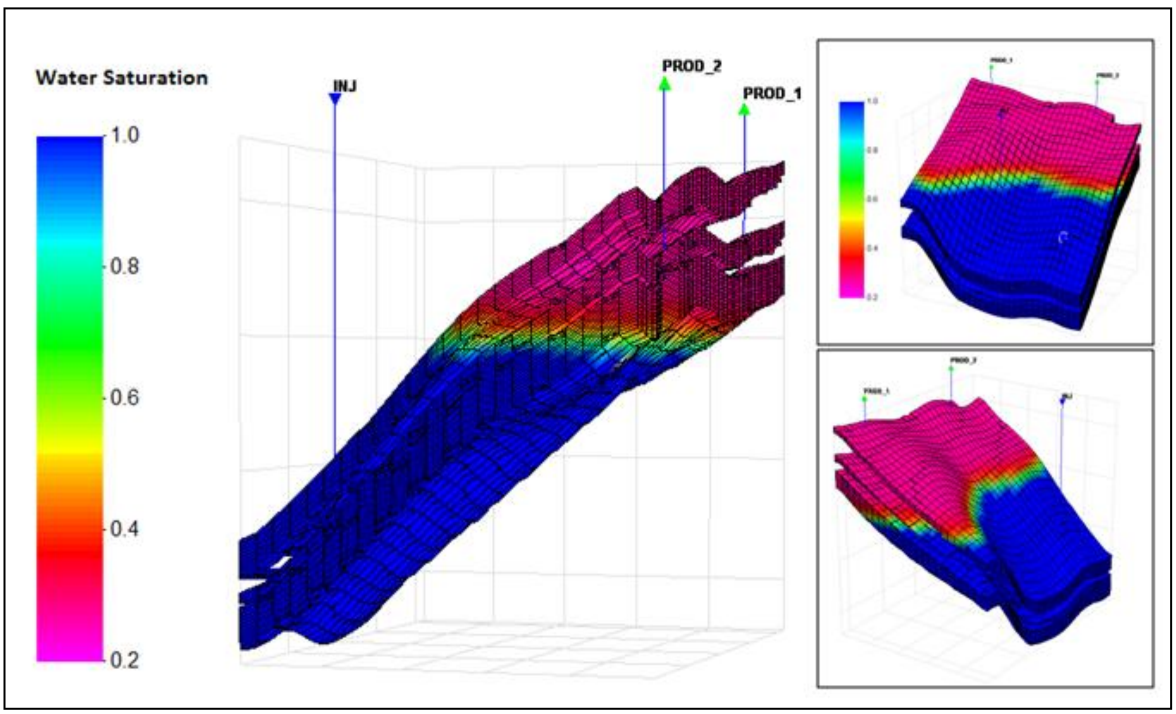


Figure 6 - 17. Simulation grids with initial water saturation distribution, field case III

Simulation Case Study:

The objective of this study was primarily to apply UTGEL to a more complex reservoir model and also investigating the effect of PPG on conformance control as an optimization study. In this case study, we performed six simulations to simulate the waterflood performance and five treatments with different sizes of PPG particles:

1) Waterflood (base case), comprised of 1,500 days (or 0.25 PV) of water injection
2) Five cases with different sizes of PPG (see Table 6-3), comprised of 500 days of pre-treatment water injection, 300 days of PPG suspension injection, and 700 days of post-treatment water injection

Table 6 - 3. Selected PPG sizes for field case III

Case	U.S. Mesh	Particle size (micron)
PPG1	100	149
PPG2	140	105
PPG3	170	88
PPG4	200	74
PPG5	230	63

Note that the actual size of PPG that propagates through the reservoir is after swelling. In this study, we used fixed parameters of 30 and 0.3 for swelling ratio calculation (see the swelling equation in Chapter 3, note that the unit used in the simulation was English unit, not Metric unit).

The simulation input parameters of Field case III are given in Table 6-4. All input parameters were the same in all simulations with the exception of PPG particle size. Sensitivity analysis was conducted to optimize the incremental oil recovery by selecting an appropriate size of PPG. The complete input data set can be found in Appendix C-3. Note that some of the data (for example, grid permeability) could not be shown due to excessive amount of data.

Table 6 - 4. Input parameters for field case III

Model	3-Dimentional Cartesian
Number of gridblocks	24 x 31 x 47
Δx, Δy, Δz	83, 82, 1.82 ft
Porosity	0.17 (avg), 0.28 (max)
Permeability	90 mD (avg), 1580 mD (max)
Dykstra Parsons coefficient	0.69
Ratio of Kv/Kh	0.1
OOIP	2.03 MMSTB
Oil viscosity	2.5 cp
Water viscosity	0.5 cp
Temperature	180 °F
Initial reservoir pressure	2915 psi (at OWC)
Production bottomhole pressure constraint	600, 1200 psi
Injection rate	1200 bbl/day
Total injection period	1500 days (0.25 PV)
Injection PPG concentration	2000 ppm

Simulation Results:

Figures 6-18, 6-19, and 6-20 show the plots of oil rate, water cut, and oil recovery versus time for each treatment scenario. The results suggested that all PPG treatments led to incremental oil recovery. For this particular field simulation, it can be observed that the performance of PPG was different when a different size of PPG was chosen. The reduction in water cut varied between approximately 5% to 10% and so as the oil recovery, 15% to 19%.

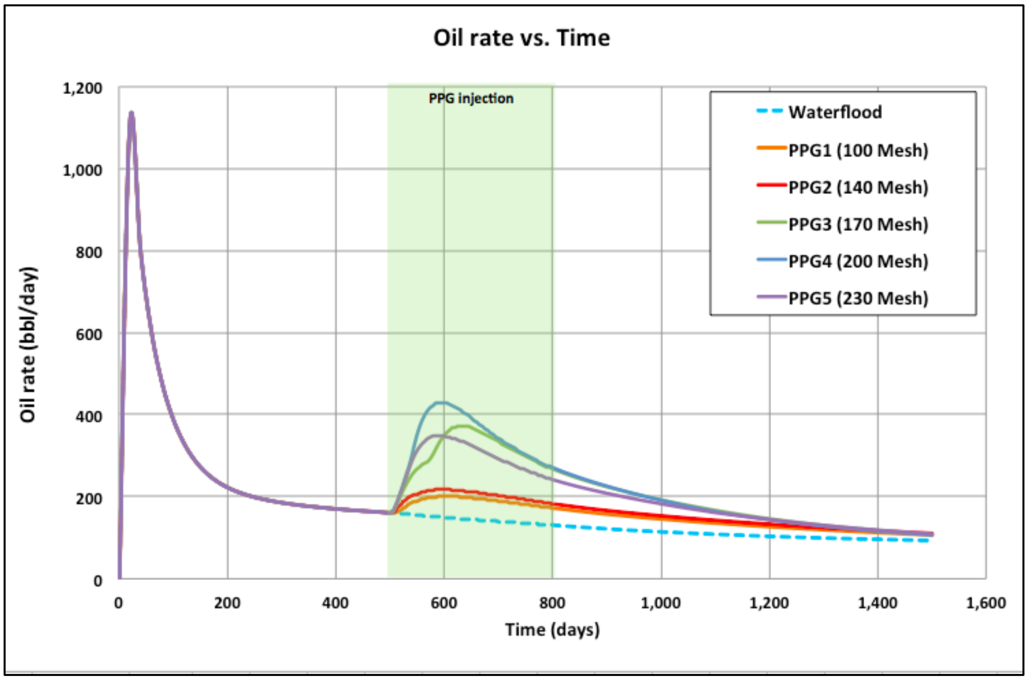


Figure 6 - 18. Oil rate vs. time, field case III

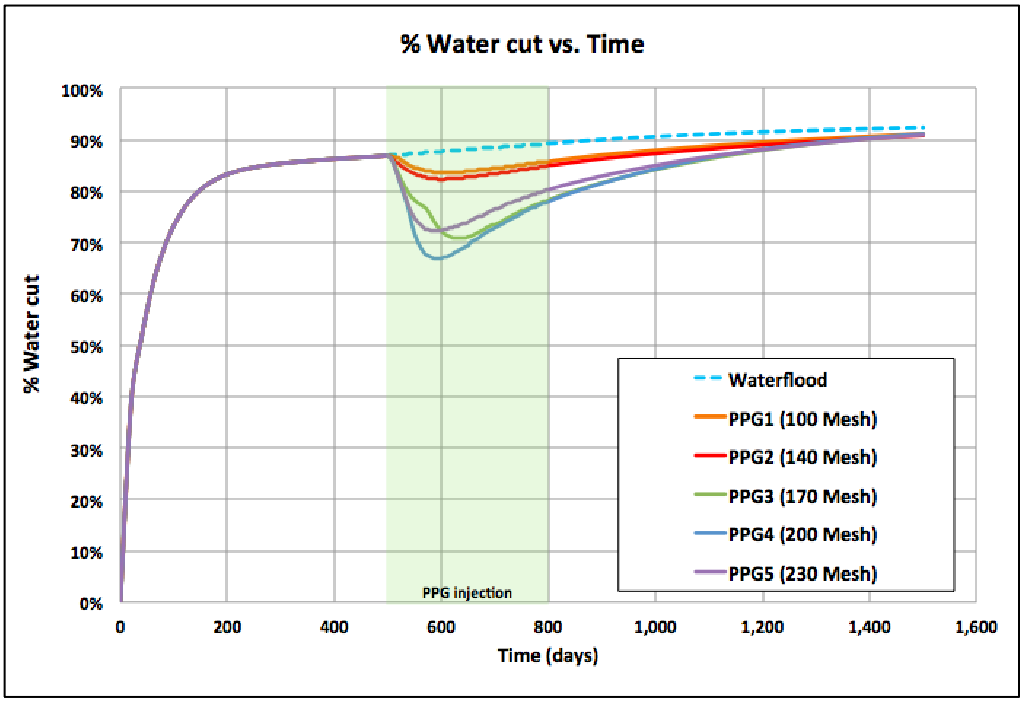


Figure 6 - 19. Water cut vs. time, field case III

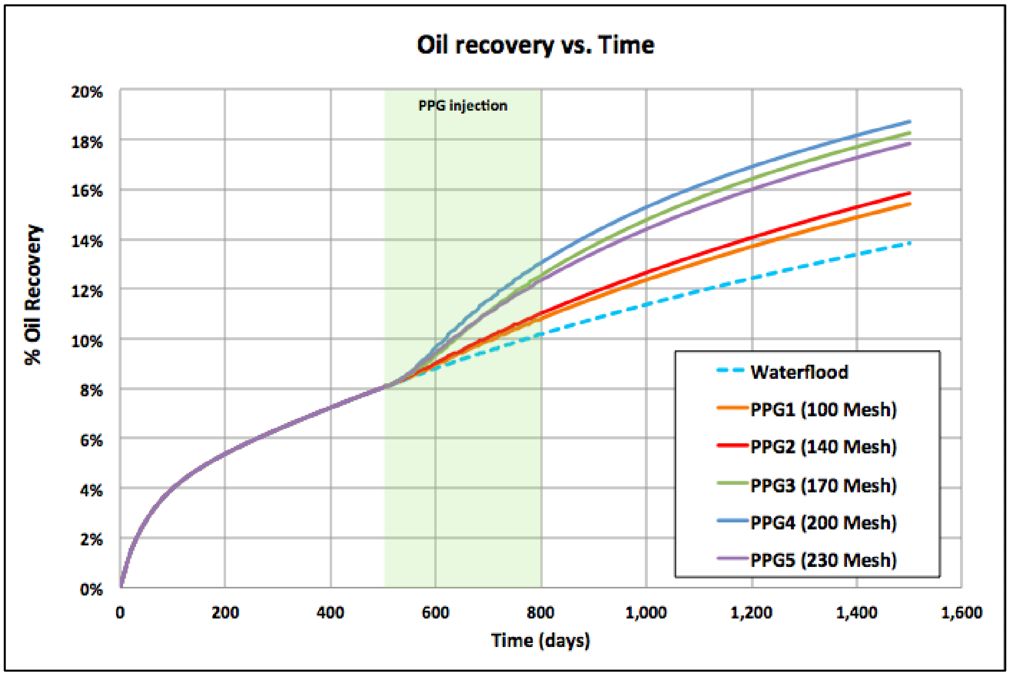


Figure 6 - 20. Oil recovery vs. time, field case III

Table 6-5 summarizes the incremental oil produced with respect to the size of PPG used. Evidently, the smaller size of PPG (170 - 230 U.S. Mesh) was more beneficial as they resulted in an incremental of more than 80,000 bbls while the larger PPGs (100 - 140 U.S. Mesh) resulted in less than 40,000 bbls incremental. Figure 6-21 demonstrates the comparison of cumulative oil recovery from each scenario as a fraction of OOIP. It can be observed that the PPG4 case with the 200-Mesh size gave the highest oil recovery. As we reduced the PPG size from 100 to 200 Mesh, the oil recovery continuously increased from 15.4% to 18.7%. However, further reduction of PPG size from 200 to 230 U.S. Mesh gave the opposite trend. There exists an optimum PPG size for each application. Very large particles would not propagate through the pore throats and very small PPGs would just pass through or be adsorbed onto a rock surface.

Table 6 - 5. Simulation results for field case III

Case	Particle size (micron)	Cumulative oil (bbls)	Incremental oil (bbls)
Base case (WF)	-	282,332	-
PPG1 (100 mesh)	149	313,338	31,006
PPG2 (140 mesh)	105	322,145	39,813
PPG3 (170 mesh)	88	371,263	88,931
PPG4 (200 mesh)	74	380,506	98,174
PPG5 (230 mesh)	63	362,652	80,319

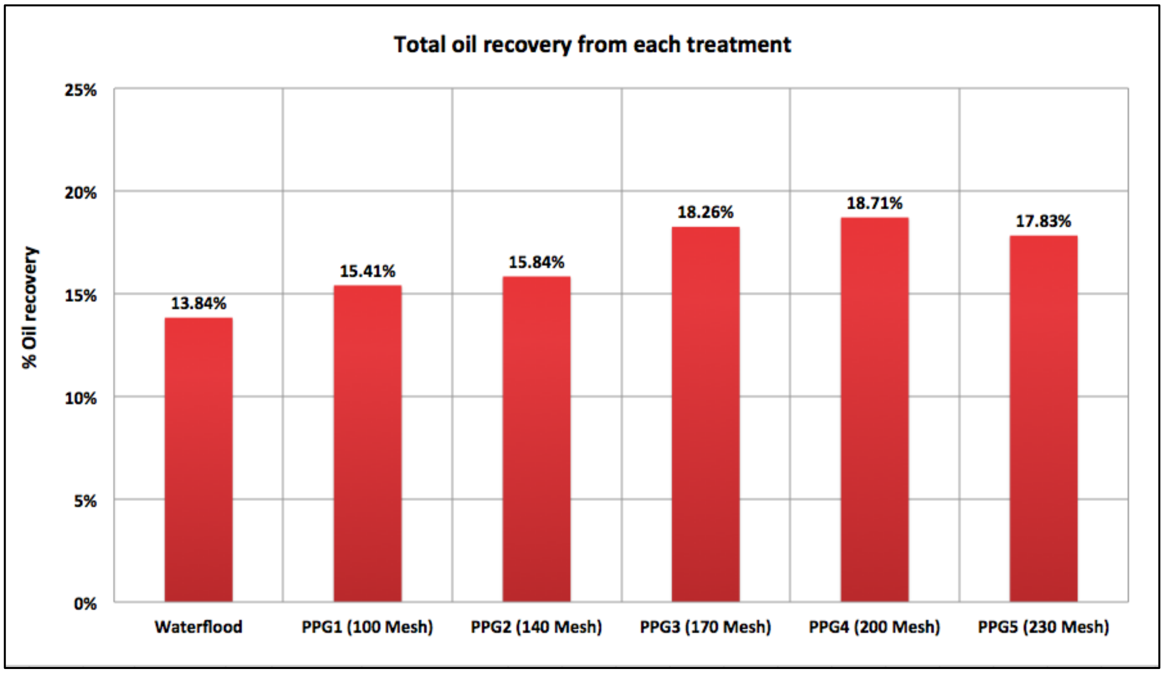


Figure 6 - 21. Comparison of oil recovery from each scenario, field case III

Summary and Conclusions:

PPG simulations in a more complex field case were successfully performed. Compared to the waterflood, with the same amount of water injected, PPG treatment could lead to an incremental oil recovery ranging from 1 - 5%. The incremental oil produced varied with the PPG particle size. According to the simulation results, the smaller particle size in the range of 170 - 230 U.S. Mesh was more effective than the larger sizes of 100 - 140 U.S. Mesh. This could be due to the fact that the permeability in the vicinity of the injection well is exceptionally low; less than 100 mD. Sensitivity analysis on particle size, thus, played an important role in finding the optimum size of PPG that can best propagate through the reservoir. With proper design, a PPG treatment could increase the recovery of this field by over 98,000 bbls compared to waterflood. The results of this case study suggest that, as a wide range of pore throat distribution exists in the reservoir, the PPG design can be optimized by simulating and selecting an optimal PPG size. However, it should be noted that the optimal size selection of PPG is utterly specific to each field and the rock pore structure.

In addition, it is worth pointing out that the incremental oil recovery from PPG treatment in this case study was not as significant as those of previous cases. Again, this was likely owing to the low permeability around the injection region that limited the application of PPG. The areas with a high contrast of permeability both areally and vertically were rather close to updip producers. Other conformance control methods which can be activated in-depth, such as temperature sensitive microgels, should be investigated for improving sweep efficiency in this field.

Chapter 7: Applications of Embedded Discrete Fracture Model (EDFM) Approach in Gel Transport Simulation

7.1. Introduction to Embedded Discrete Fracture Model

Target reservoirs for PPG treatments are typically those with fractures or very high permeability streaks. The ability to model the propagation of PPG through a fractured reservoir was considered as a new challenge for this research study. Numerical simulation of fluid-flow in fractured reservoirs is complex due to the large contrast between matrix and fracture permeabilities, the extremely small size of fracture apertures, and the unstructured grid.

Discrete fracture models or DFMs have been developed for realistic simulation of fractured reservoirs but they are numerically difficult to implement and computationally expensive. Also, they require generating unstructured grids which imposes more complexity for field simulations (Figure 7-1).

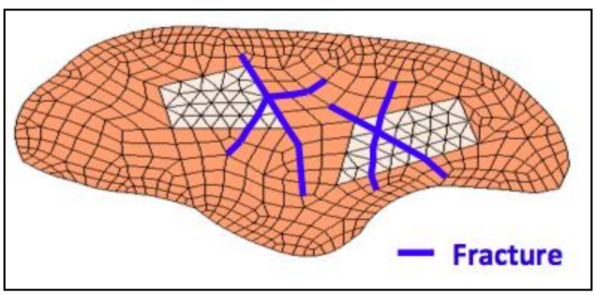


Figure 7 - 1. Discrete fracture model with unstructured gridding

To eliminate problems associated with unstructured gridding, a new model called Embedded Discrete Fracture Model (EDFM) has recently been developed and implemented in UTGEL. First, Li and Lee (2006) adopted a hierarchical modeling approach to represents fractured with different length scales. Later, Moinfar et al. (2013) employed this model to represent fractures with different dip angles and orientations in an in-house reservoir simulator called GPAS (Figure 7-2).

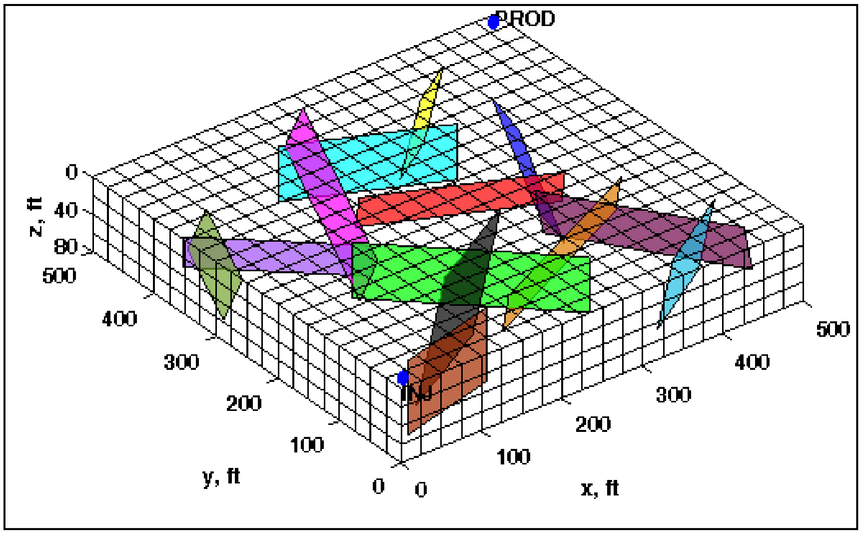


Figure 7 - 2. Embedded discrete fracture model (Moinfar, et al., 2012)

With this novel discrete fracture modeling approach, in this study, the ability to explicitly incorporate the effect of fractures or high permeability conduits has been integrated into UTGEL for the first time. The developed EDFM approach has finally enabled multiple sets of fractures with any dip and strike angles to be included in the simulation of gel and microgel treatments for conformance control. The concept of EDFM is briefly summarized in this chapter. Nevertheless, complete details of EDFM implementation can be assessed in Shakiba (2014).

The main objectives and scopes of this chapter were to verify the feasibility of EDFM and demonstrate its applications in a gel transport simulation. Primarily, we conducted simulations to validate the implementation of EDFM in UTGEL by running the EDFM in parallel with the conventional fine-grid model and comparing the results. Then, to show the advantages of EDFM in gel transport simulation, two case studies were simulated with applications of PPG in two rather challenging scenarios. First, PPG simulation was investigated in a fractured reservoir model with a $\pm 50^{\circ}$ slant fracture plane cutting across the reservoir between the injector and producer pair. Second, PPG simulation was conducted in a reservoir model where a slightly complex fracture conduit was positioned in the middle of the reservoir creating a super high permeability pathway between the injector and producer pair.

7.2. Implementation of Embedded Discrete Fracture Model

In this model, the fracture control volumes are considered as non-neighboring connections (NNC) in the simulator. A preprocessor (Sergio, 2014) is required to locate the fractures and to calculate the transmissibility factors between non-neighboring connections. Since the fracture control volumes are introduced inside the matrix grid domain, three new connections are defined based on non-neighboring connections. They are (I) matrix-fracture connection, (II) fracture-fracture intersection, and (III) fracture-fracture connection of the same fracture plane. For each of these new connections, a transmissibility factor (T) is calculated using a preprocessing code.

I) For matrix-fracture connection (Connection Type I),

$$T = \frac{kA}{d} \qquad \text{(7-1)}$$

where A is the area of fracture cell inside the grid block, k is the harmonic average of the permeabilities, and d is the normal distance between center of matrix gridblock and fracture cell.

II) For fracture-fracture intersection (Connection Type II),

$$T = \frac{kA}{d} = \frac{T_1 T_2}{T_1 + T_2} \qquad \text{(7-2)}$$

where

$$T_1 = \frac{k_{f1}\omega_{f1}L}{d_{f1}}\ , \qquad \text{(7-3)}$$

$$T_2 = \frac{k_{f2}\omega_{f2}L}{d_{f2}} \qquad \text{(7-4)}$$

and k is the fracture permeability, ω is the fracture aperture, L is the length of intersection line (between 2 fractures) bounded in a gridblock, and the subscripts $f1$ and $f2$ represent the intersected fracture number 1 and number 2.

III) For fracture-fracture connection of the same fracture plane (Connection Type III),

$$T = \frac{kA}{d} \qquad \text{……..……………………..(7-5)}$$

where k is the fracture permeability, A is the length of intersection times the aperture, and d is the distance between center of two segments.

7.3. Validation of EDFM Implementation in Gel Transport Model

Comparison between EDFM and conventional fine-grid model

To validate the implementation of EDFM in UTGEL, we generated two 2D models; one was a fine-grid model in which a fracture was modeled using high permeability gridblocks (same as those of the case studies in Chapter 5), and the other was an embedded discrete fracture model of which the fracture was embedded using the EDFM approach. The fracture was placed in the exact same location in each model. Identical PPG treatments were simulated in both models. Then the simulation results obtained were compared to ensure that the results from the EDFM were in agreement with those from the conventional fine-grid model. The computational times used in the simulations of both models were also recorded for comparison.

Figure 7-3 illustrates the conventional fine-grid model created with the given permeability distribution. Figure 7-4 illustrates the 3-dimensional view of the embedded fracture generated by the preprocessor for the EDFM. Both models were 50-ft long, 50-ft wide, and 3-ft thick with a 30-ft long fracture placed at the exact same location. In the conventional grid model, the size of all gridblocks was set equal to that of the fracture aperture, which was 0.25 ft, to eliminate any inconsistency from local grid refinement. The simulation of gel transport was conducted on a 2-dimentional basis, i.e. fluid only transported in X and Y directions, to avoid excessively long computational time in the conventional fine-grid model simulation.

The PPG treatment used in both model simulations consisted of 0.4 PV of pre-treatment water injection, 0.2 PV of PPG suspension injection, and lastly 0.4 PV of post-treatment water injection. Table 7-1 shows the simulation parameters used for the two models.

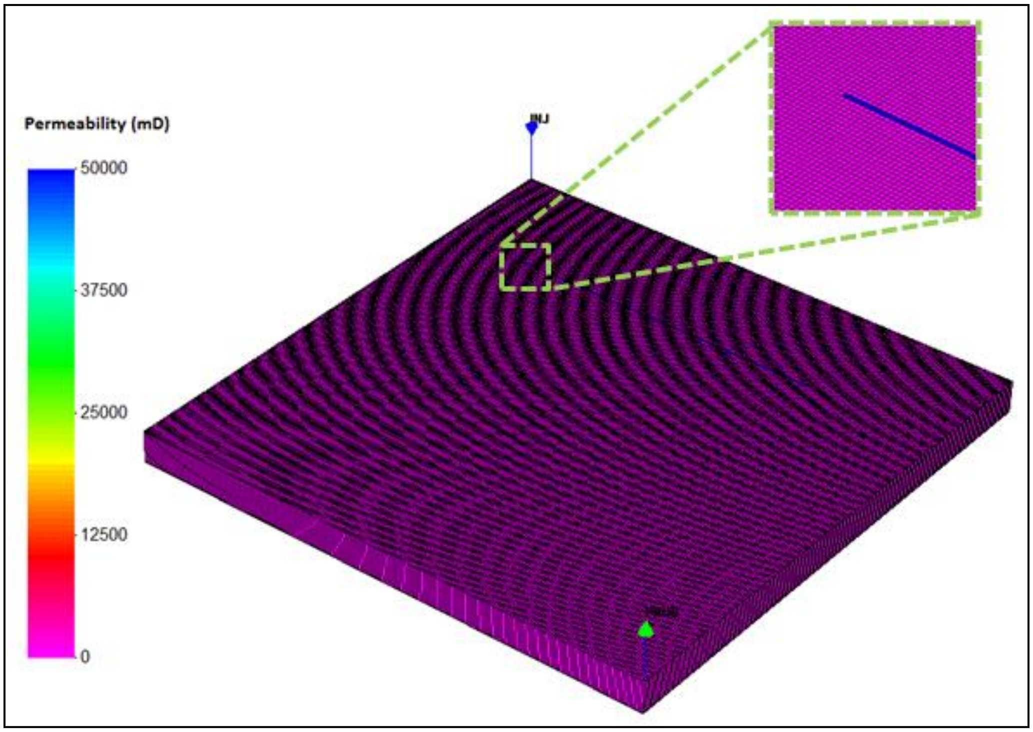


Figure 7 - 3. Conventional fine-grid model created with the given permeability distribution

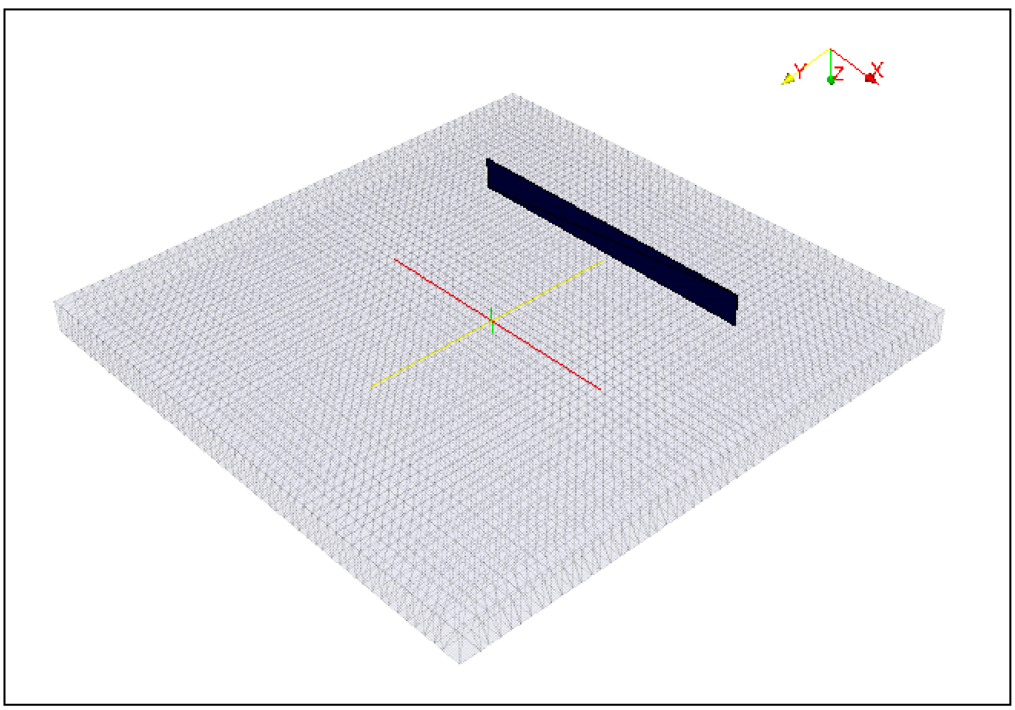


Figure 7 - 4. 3D view of the embedded fracture generated by the preprocessor for EDFM

Table 7 - 1. Input parameters for fine-grid model and EDFM simulations

Parameters	**Fine-grid Model**	**EDFM**
Model	2D Cartesian	2D Cartesian
Number of matrix gridblocks	160 x 160 x 1	200 x 200 x 1
Number of fracture gridblocks (NNC)	96	-
Δx, Δy, Δz	0.3125, 0.3125, 3	0.25, 0.25, 3
Porosity	0.3	
Matrix Permeability	100 mD	
Fracture Permeability	50,000 mD	
Oil viscosity	5 cp	
Water viscosity	1 cp	
Initial reservoir pressure	2000 psi	
Production bottomhole pressure	500 psi	
Injection rate	100 ft^3/day	
Total injection period	1.0 PV	
Injection PPG concentration	1000 ppm	

The simulation results are summarized in Table 7-2 and plotted for comparison purpose in Figure 7-5, 7-6, and 7-7. The differences between the results from EDFM and those from the fine-grid model are given in Table 7-2. Both simulations are in good agreement. Figure 7-5 demonstrates oil recoveries from both models, while Figure 7-6 demonstrates water cut results, and Figure 7-7 shows the similarity of the average pressure profiles obtained from the two models.

It can be concluded from all the comparisons that the EDFM results were in agreement with those of the fine-grid model. In addition, while it took almost 160 CPU hours to complete the fine-grid simulation, it only took 40 CPU hours using the EDFM method. This is due to the fact that the EDFM does not require grid refinements to establish a fracture with a small aperture size in a large-scale reservoir model. This suggests that the implementation of EDFM in gel transport modeling is feasible and that the EDFM approach can be employed in improving gel transport simulations.

Table 7 - 2. Results from the fine-grid model and EDFM simulations

Simulation Results	Fine-gird	EDFM	Difference
Oil recovery from pre-treatment water injection (%)	47.21	46.63	0.58
Total oil recovery (%)	66.88	67.01	0.13
Water breakthrough time (PV injected)	0.26	0.24	0.02
Final average reservoir pressure (psi)	3449	3377	72
Simulation run time (hrs)	159	40	-

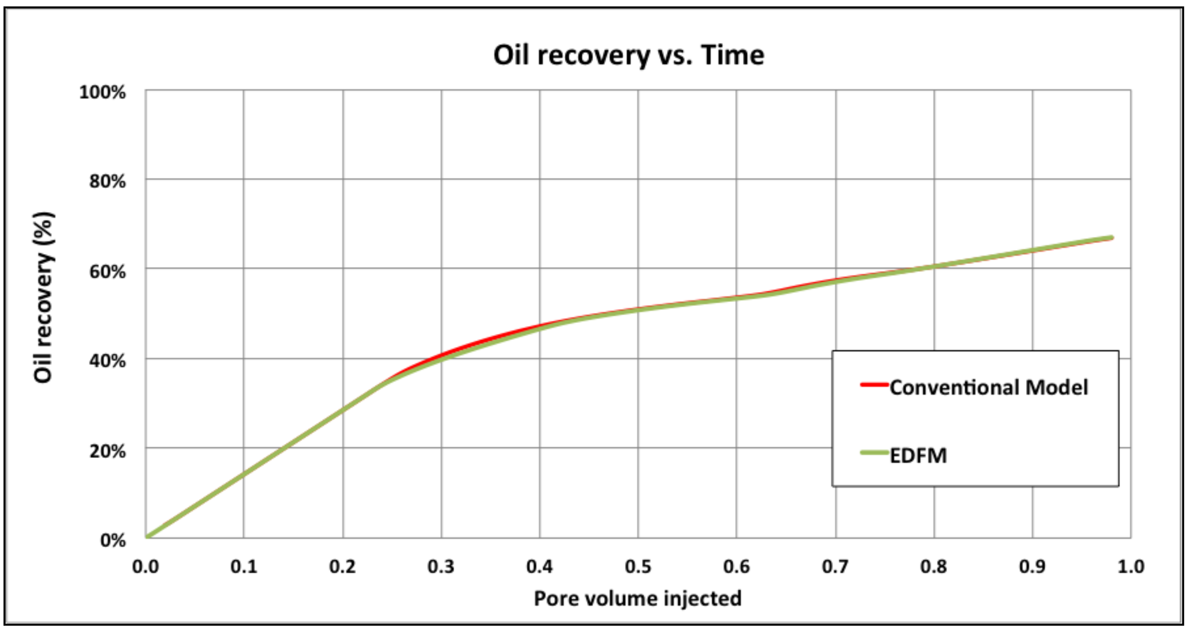


Figure 7 - 5. Oil recovery profiles obtained from fine-grid model and EDFM simulations

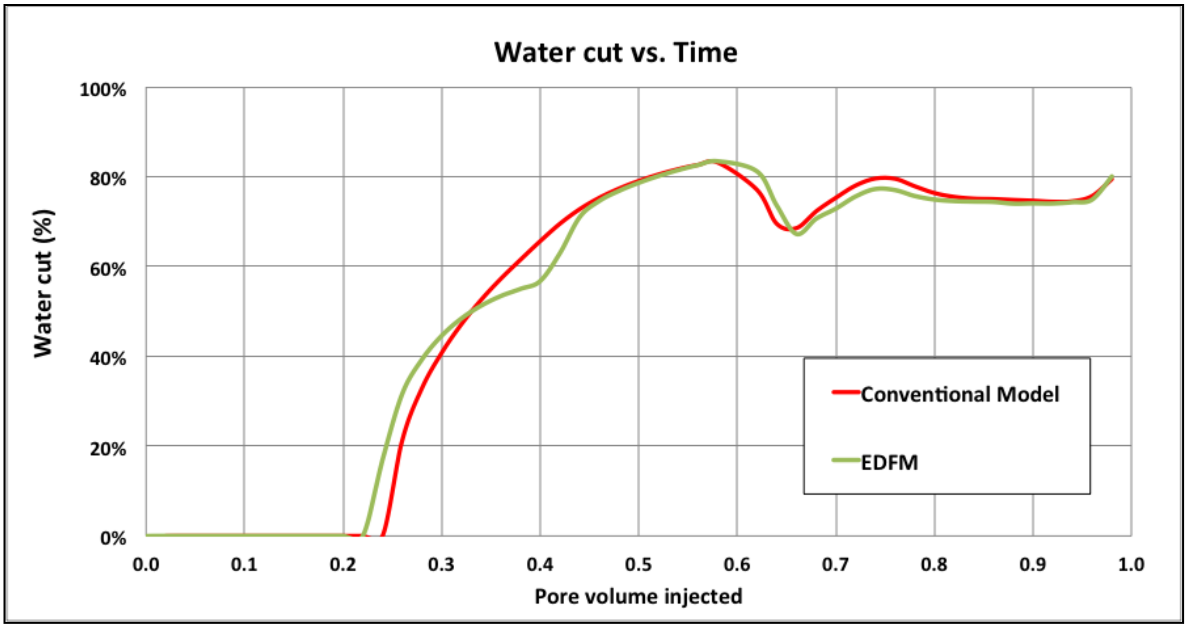


Figure 7 - 6. Water cut profiles obtained from fine-grid model and EDFM simulations

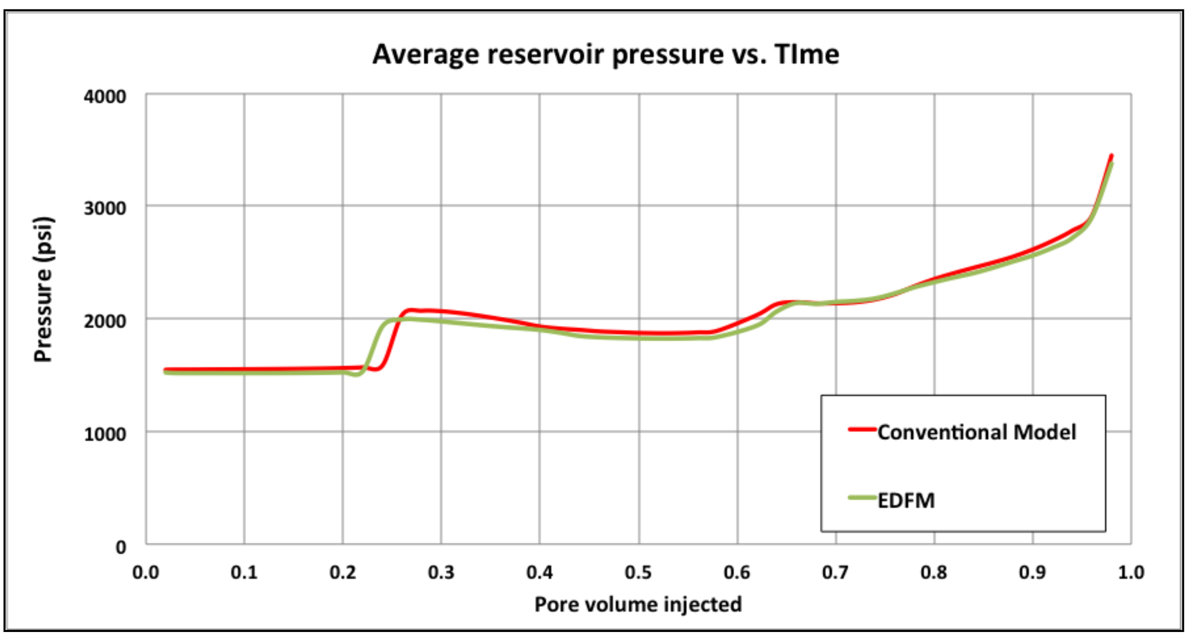


Figure 7 - 7. Average reservoir pressure profiles obtained from fine-grid model and EDFM simulations

7.4. Slanted Fracture Plane Model

To substantiate the benefits of EDFM in gel transport simulation, we performed PPG simulations in a synthetic model where a $\pm 50^{\circ}$ slanted fracture plane was placed through the reservoir between the injector and producer pair. With the preprocessor, the slanted fracture plane was created and embedded precisely in the reservoir model, and the transmissibility factors between non-neighboring connections were calculated. The 3-dimensional views of the slanted fracture plane generated are shown in Figure 7-8. The PPG treatments used in this case study consisted of 0.8 PV of water injection and 0.2 PV of PPG suspension injection. However, to investigate the effect of PPG injection timing, four different simulations were carried out in this study:

1) Waterflood, comprised of 1.0 PV of water injection
2) Early PPG injection, comprised of 0.1 PV of pre-treatment water injection, 0.2 PV of PPG suspension injection, and 0.7 PV of post-treatment water injection
3) Intermediate PPG injection, comprised of 0.3 PV of pre-treatment water injection, 0.2 PV of PPG suspension injection, and 0.5 PV of post-treatment water injection
4) Late PPG injection, comprised of 0.5 PV of pre-treatment water injection, 0.2 PV of PPG suspension injection, and 0.3 PV of post-treatment water injection

The parameters used in the simulation are given in Table 7-3. The complete inputs for the simulation run can be found in Appendix D-1. The impact of having the slanted fracture plane in this case study was also quantified and summarized in Appendix D-1.

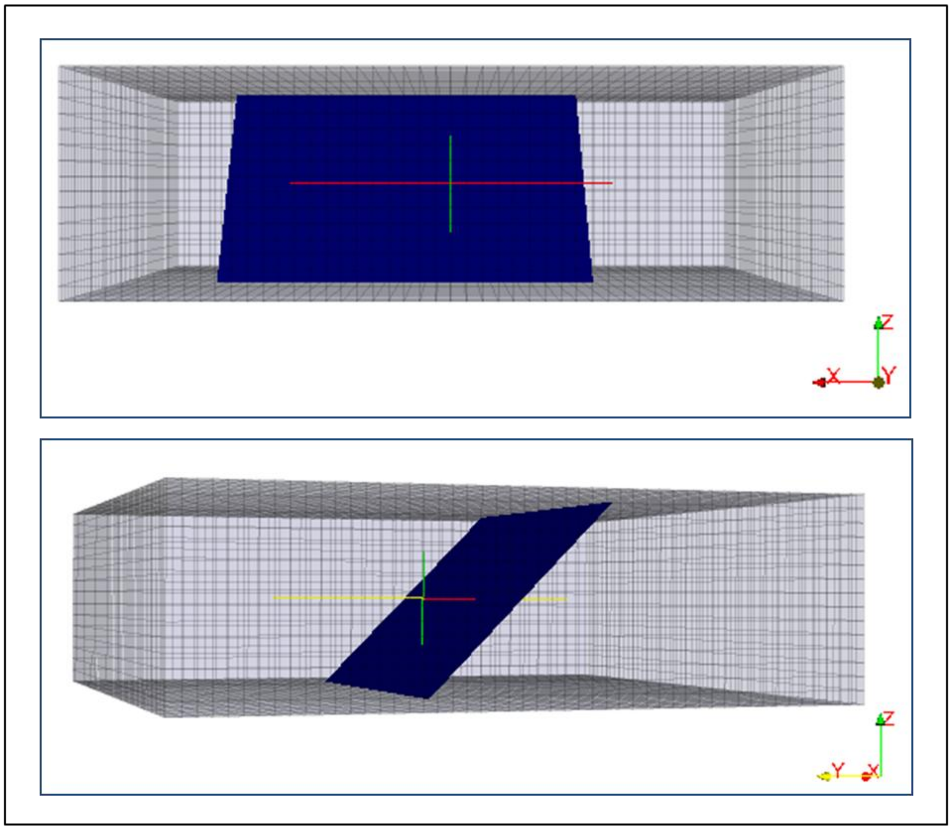


Figure 7 - 8. 3D views of the slanted fracture plane generated by the preprocessor for EDFM

Table 7 - 3. Input parameters for the slanted fracture plane model

Model	3-Dimentional Cartesian
Number of matrix gridblocks	50 x 50 x 15
Number of fracture gridblocks (NNC)	884
Δx, Δy, Δz	2, 2, 2 ft
Fracture aperture	0.15 ft
Porosity	0.25
Permeability	100 mD
Fracture permeability	50,000 mD
Ratio of Kv/Kh	0.1
Oil viscosity	5 cp
Water viscosity	1 cp
Initial reservoir pressure	1100 psi
Production bottomhole pressure constraint	1000 psi
Injection rate	1000 ft^3/day
Total injection period	1 PV
Injection PPG concentration	1000 ppm

To demonstrate the behavior of the injectant (water) inside the fracture plane model created using EDFM approach, snapshots of water saturation profile by grid block and a sector model with a proper cut plane were generated. Figure 7-9 shows the water saturation profile of the base case simulation of the slanted fracture plane model at 0.5 PV, along with a sector model cut by a plane at a 50° slanted angle. It can be observed in Figure 7-9 that the injected water propagated faster through the slanted fracture plane creating an abnormally slanted shape of higher water saturation at the producer end.

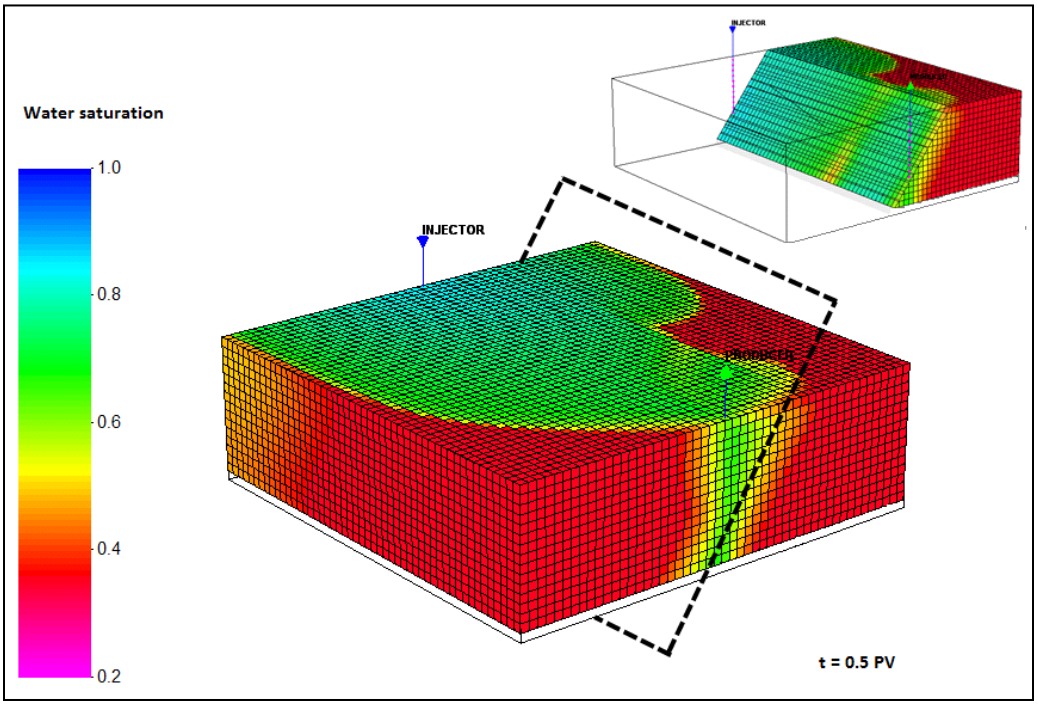


Figure 7 - 9. Water saturation profile for waterflood in a slanted fracture plane model at an output time of 0.5 PV

The simulation results of all 4 cases are summarized in Table 7-4. The incremental oil recoveries varied between 6% and 13% due to different PPG injection timing design. Figure 7-10 and 7-11 illustrate the oil recovery and water cut profiles from all cases, respectively. The earlier PPG injection resulted in higher incremental oil recovery for this case study. The water cuts plotted in Figure 7-11 reveal that the improvement in water cut became less significant from the early PPG treatment (approximately 35% water cut reduction) to the late treatment (approximately 20% water cut reduction). The simulation run times used for all the simulation cases were less than 15 CPU hours.

Table 7 - 4. Simulation results for the slanted fracture plane model

Simulation Cases	Start time of PPG injection (PV)	Oil recovery (%)	PPG Incremental recovery (%)
1. Waterflood	-	55.77	-
2. Early PPG treatment	0.1	68.25	12.49
3. Intermediate PPG treatment	0.3	65.75	9.99
4. Late PPG treatment	0.5	62.55	6.78

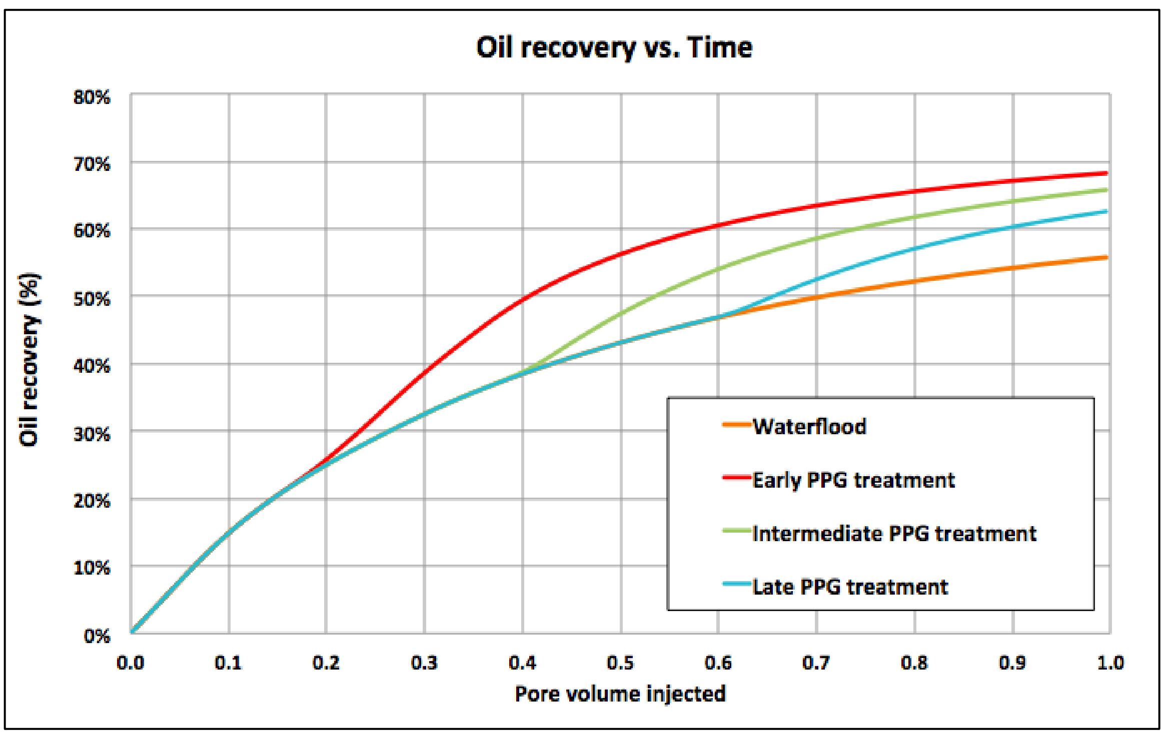


Figure 7 - 10. Oil recovery vs. time, slanted fracture plane model

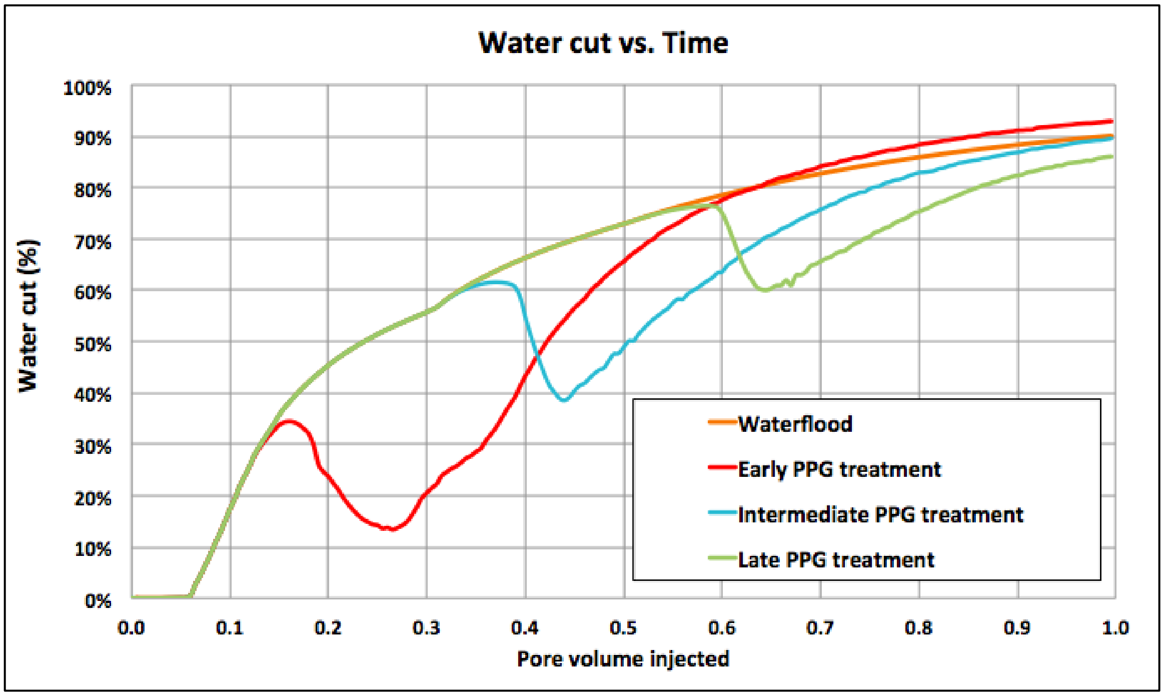


Figure 7 - 11. Water cut vs. time, slanted fracture plane model

7.5. Complex Fracture Conduit Model

Another scenario where EDFM can be useful is illustrated here with a complex fracture conduit model. Many fracture streaks with different dip angles were generated to create an extensive fracture conduit in this case study. The preprocessor was employed to embed the conduit at the precise coordinates of the reservoir model and calculate the transmissibility factors between non-neighboring connections. The 3-dimensional views of the fracture conduit embedded are shown in Figure 7-12. For this study we aligned the conduit to be in one vertical plane so that the injection and production wells could be placed directly on the opposite sides of the conduit. Hence, it was convenient to visualize the fluid behavior around the conduit and the wells.

Two simulations were performed for this case study; (1) the waterflood case consisted of 1 PV of water injection, and (2) the PPG treatment case consisted of 0.3 PV of pre-treatment water injection, 0.2 PV of PPG injection, and 0.5 PV of post-treatment water injection. The simulation parameters are given in Table 7-5. The complete input file can be found in Appendix D-2 as well as the brief review of the impact of the fracture conduit on the generated reservoir model.

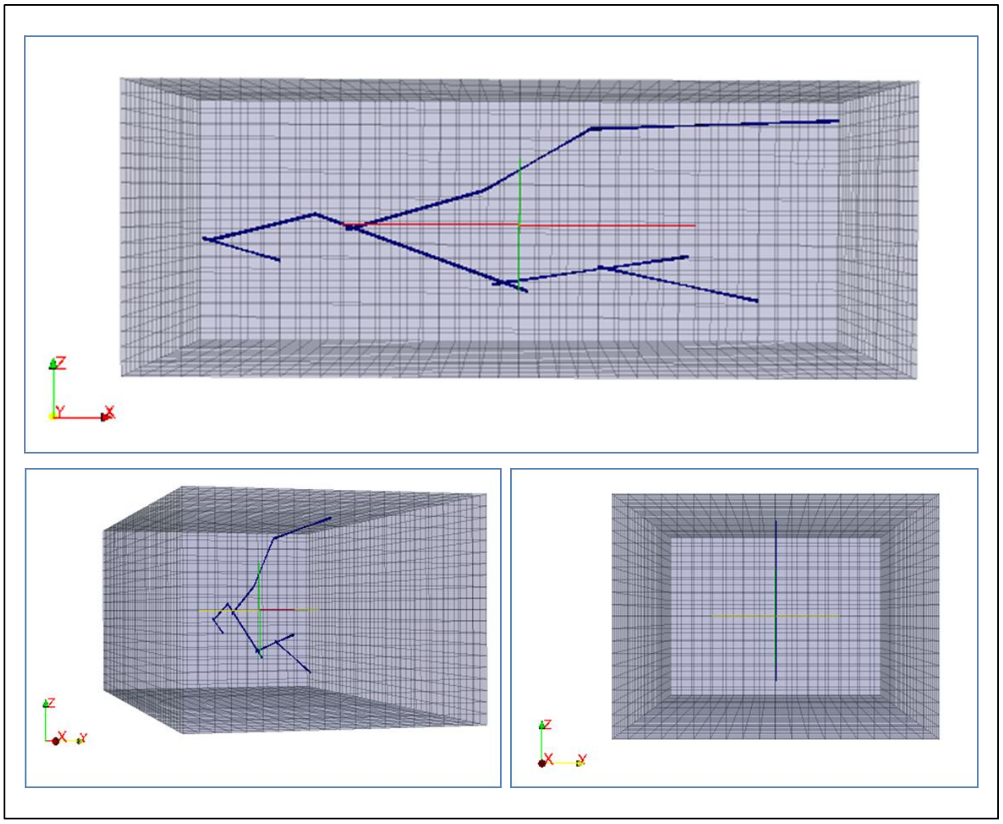


Figure 7 - 12. 3D views of the fracture conduit generated by the preprocessor for EDFM

Table 7 - 5. Input parameters for the complex fracture conduit model

Model	3-Dimentional Cartesian
Number of matrix gridblocks	40 x 20 x 20
Number of fracture gridblocks (NNC)	85
Δx, Δy, Δz	2, 2, 1.5 ft
Fracture aperture	0.25 ft
Porosity	0.25
Permeability	50 mD
Fracture permeability	80,000 mD
Ratio of Kv/Kh	0.25
Oil viscosity	2.5 cp
Water viscosity	1 cp
Initial reservoir pressure	1100 psi
Production bottomhole pressure constraint	800 psi
Injection rate	600 ft^3/day
Total injection period	1 PV
Injection PPG concentration	2000 ppm

The behavior of the injectant (water) inside the fracture conduit model created with the EDFM approach is demonstrated in Figure 7-13. It can be observed in the figure that the injected water propagated faster through the complex fracture conduit creating an abnormal front of the injected water, which resulted in partial water breakthrough at the producer's end at the output time of 0.3 PV of water injection.

The results of oil recovery versus pore volumes injected for the waterflood and the PPG treatment simulations are shown in Figure 7-14. The results of the simulation suggested that a PPG treatment led to an incremental oil recovery of approximately 7%. The water cut versus PV was also plotted in Figure 7-15. For the PPG case, the water cut reduction as high as 20% was observed at the producer after about 0.2 PV of PPG injection. The simulation run time for the waterflood and PPG treatment were 17.5 and 19.7 CPU hrs, respectively.

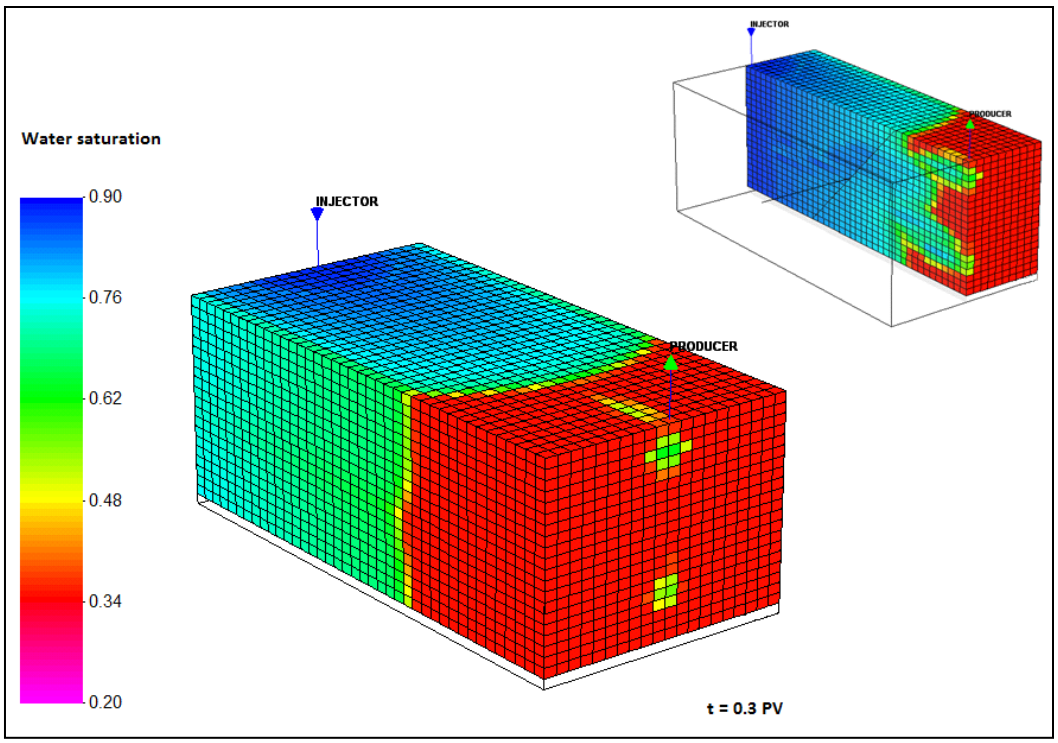


Figure 7 - 13. Water saturation profile for waterflood in a fracture conduit model at an output time of 0.3 PV

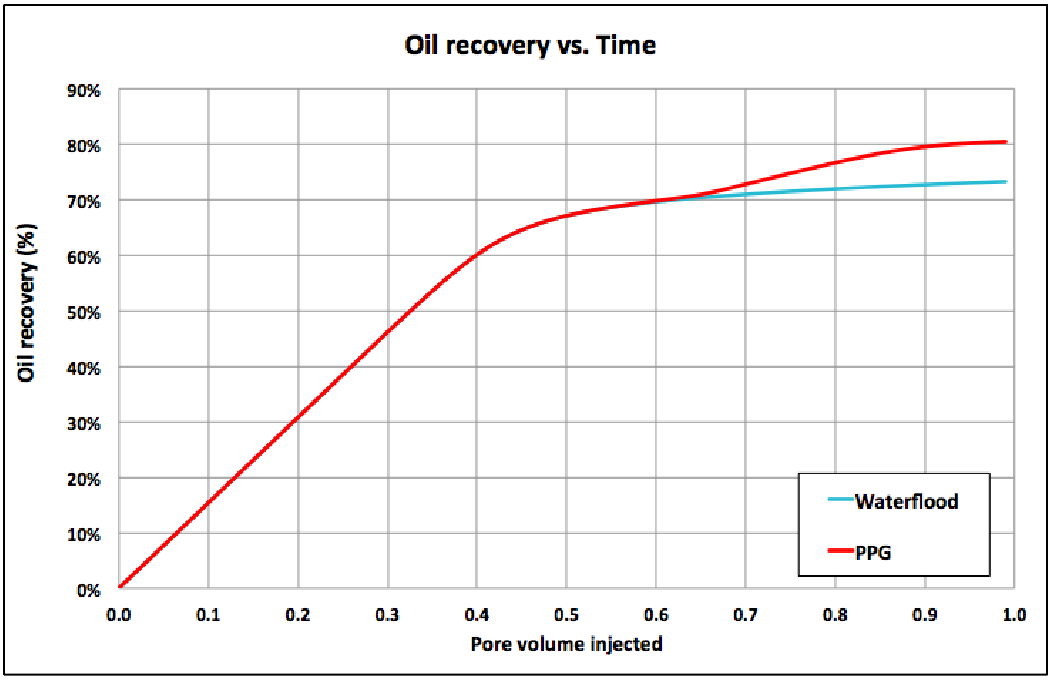


Figure 7 - 14. Oil recovery vs. time, fracture conduit model

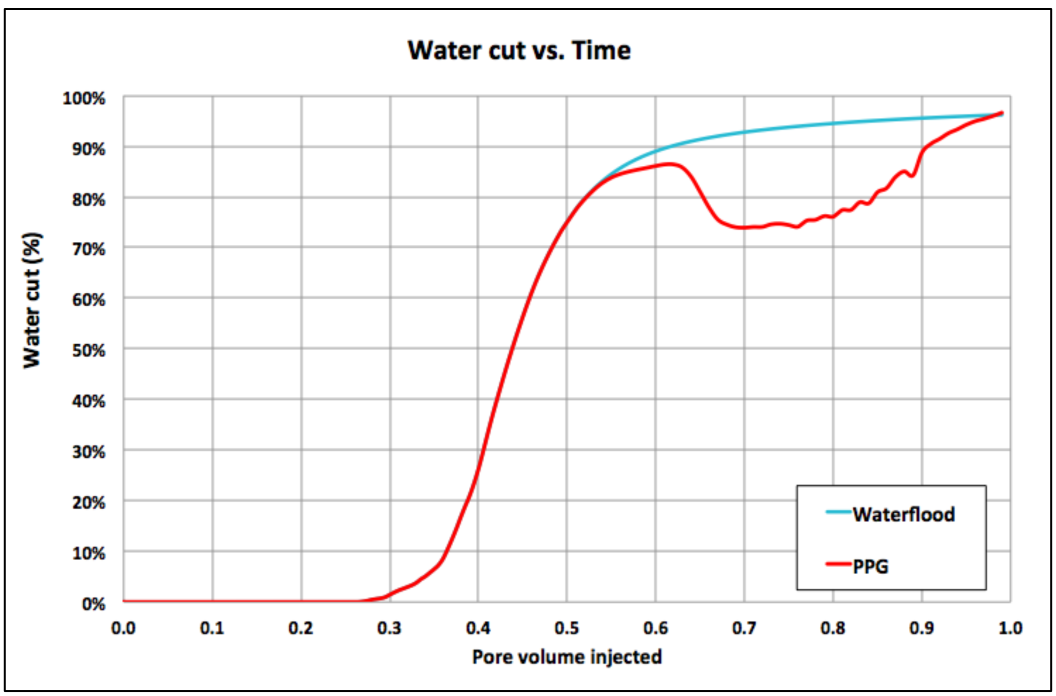


Figure 7 - 15. Water cut vs. time, fracture conduit model

From the two case studies, a slanted fracture plane and a complex fracture conduit with several dip angles were successfully generated and placed in the reservoir models using the EDFM preprocessor. With the non-neighboring connections (NNC) concept of the EDFM approach, the simulations of fluid and gel transport in reservoirs containing these uncharacteristic fracture passages were successfully performed with representative results. The computational times used in the simulations were fairly reasonable considering the number of gridblocks and the contrast between the size of the fracture aperture and the matrix gridblocks. No local grid refinement was required and the fractures were able to be placed in more realistic manners.

Chapter 8: Conclusions and Recommendations

8.1. Conclusions

Although the developed simulator requires further improvement and validation against wider ranges of reservoir and fluid conditions, the following conclusions can be drawn from this research study:

1. UTGEL, the university of Texas conformance control reservoir simulator, has been successfully developed to simulate the propagation of preformed particle gel (PPG) in improving waterflood sweep efficiency through resistance factor or permeability reduction effects. The results of the simulation of a series of PPG laboratory experiments agree with the experimental data. This suggests that the simulator works well and that the parameters used in simulation are reasonable.
2. We simulated the application of PPG in various reservoirs scenarios including layered reservoirs with permeability contrasts and reservoirs with high permeability streaks or conduits. PPG can greatly reduce the permeability of an extremely high permeability fracture or conduit. The success of a PPG treatment is dependent on how well PPG can selectively penetrate into the high permeability passages while minimizing its penetration into the lower permeable or unswept regions. The Dykstra Parsons coefficient can be helpful in approximating the potential incremental gain from a PPG treatment. The benefit of PPG in improving waterflood sweep efficiency can occur both areally and vertically.
3. Several simulations of PPG treatments in a reservoir model based on an actual field were successfully performed. UTGEL can be used as a reservoir management tool for history matching, performance forecast, production optimization, and injection design.
4. Sensitivity analyses and mechanistic studies of PPG by means of simulation provide a number of oilfield applications:
    - **PPG applications in comparison with other types of gel:** Compared to other types of microgels, PPG is considered suitable for treatments of fractures or high

permeability streaks. PPG can preferentially enter into fractures or fractured-like channels while minimizing its penetration into low permeable zones. With several gel modules incorporated, UTGEL provides a capability to simulate not only PPG but also bulk gel, CDG, pH-sensitive and temperature-sensitive gels, i.e. Brightwater.

- **PPG concentration optimization:** Increasing injected PPG concentration often results in higher incremental oil recovery from the treatments. However, for any particular field, it is important to monitor the injection flowing bottomhole pressure to avoid injection induced fracturing and limit the pressure below the parting pressure.
- **PPG size selection:** A wide range of pore throat distributions usually exists in oil reservoirs, therefore gel simulation can be very helpful in selecting optimal PPG particle size. Sensitivity analysis on particle size plays an important role in finding the optimum PPG size that can best propagate through the reservoir since different fields are subjected to different heterogeneities, different well patterns, and different well spacings.
- **Timing of PPG treatment:** Early injection of PPG often results in higher incremental oil recovery. Late PPG treatment can result in significantly lower incremental recovery. Therefore, it is important to make a timely diagnosis to recognize the need for the treatment.

5. With an integration of comprehensive and mechanistic gel transport modules and a novel Embedded Discrete Fracture Modeling (EDFM) concept, both (1) gel rheological and transport properties; such as shear thinning viscosity, adsorption, and permeability reduction, and (2) multiple sets of fracture planes and conduits with dip angles and orientations, for the first time, were all captured in a numerical simulator. In this study, the implementation of EDFM was validated with a conventional fine-grid model and proved feasible with less computational time. The computationally inexpensive approach and the representative results from the generated slanted fracture plane and complex conduit models suggest a further step

toward achieving advanced and realistic modeling of gel treatments in complex reservoirs.

8.2. Recommendations

It is evident from this study that considerable scope for further work exists. The following areas of study can potentially improve the robustness and enhance the practicality of gel transport simulation.

1. **Further development of UTGEL**

   UTGEL has been modified a number of times throughout the course of this research study and apparently it is still a work in progress. Many areas, of which some are already ongoing efforts, have been proposed to improve its robustness:

   - Effect of salinity on PPG resistance factor; currently the resistance factor is expressed as a function of injection rate and input model parameters. As we know, the salinity has a direct impact on gel strength. Therefore, a new correlation was proposed to include the effective salinity in the calculation of PPG resistance factor. However, additional laboratory data is required to validate the proposed correlation (Goudarzi, et al., 2014)
   - PPG size distribution; currently the size of PPG is a constant input value. However, similar to the pore throat diameter, the diameter of PPG particle can vary. A normal distribution has been proposed to model PPG passing and blocking criteria (Wang, et al., 2013)
   - Shear rate equation; currently the effective gel viscosity can be modified using Meter’s equation. However, laboratory data should be utilized to endorse or fine-tune the associated input parameters.
   - Residual oil saturation modification by gel; it has not been entirely clear whether and how the gel treatments affect the residual oil saturation to waterflood. More laboratory experiments are required to better understand whether PPG injection has any impact on waterflood residual oil saturation.

2. Further validation with actual field performance data

Although some field case studies have been presented in this study, none of them have actually been treated with PPG yet. The studies only show that the simulations of PPG treatments were successfully performed based on actual field and reservoir data along with a number of sensitivity analysis studies that could benefit the optimization during the design phase. It is highly recommended that the simulations are compared with field results once the data become available.

Appendix

Appendix A. Input Data for PPG Experiment History Matching

A-1. Input data for CASE I, Water flow in an open fracture model (at 0.5 mm fracture width, 0.05% Brine, and 5 ml/min flow rate)

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (cm) :  1.8           PROCESS :  PROFILE CONTROL         *
CC  THICKNESS (FT) : 0.0328      INJ. PRESSURE (PSI) : -            *
CC  WIDTH (FT) : 0.00164         COORDINATES : CARTESIAN            *
CC  POROSITY :  1.0                                                 *
CC  GRIDBLOCKS :  2                                                *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
exp1_w1c1q1
CC
CC
*----HEADER
Experimental matching # 1, 1-D water flow in open fracture model (Zhang 2010)
Fracture width = 0.5 mm, Brine conc. = 0.05%, Flow rate = 5 ml/min
****************************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
       1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     20    1   1  2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     20*0.0902231
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
```

```
     1*0.00164042
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
   1*0.328084
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  0  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
     1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  0  0  0  1  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
     0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
```

```
CC    RESERVOIR PROPERTIES                                           *
CC                                                                   *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
      5
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       0      0     0      0      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     1.0
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
    20833333.33
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----PERMY(1)
     20833333.33
CC
CC VARIABLE Z-PERMEABILITY
*----PERMZC (MILIDARCY)
     20833333.33
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
     0        0       0
CC
CC VARIABLE DEPTH (FT)
*----D111
    0.0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     14.7
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
     1.0
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
   0.008547      0.0
CC
CC*******************************************************************
CC                                                                   *
CC    PHYSICAL PROPERTY DATA                                         *
CC                                                                   *
CC*******************************************************************
CC
CC
```

```
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
      0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
      0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
    0      0    0
CC
```

```
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC  S2RWC  S3RWC
     .0    .0    .0
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW     P3RW
      1.0   1.0   1.0
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W     E2W  E3W
      1.0   1.0   1.0
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     0.5     1.25   0.0
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
     62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
       0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
      0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
```

```
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
      0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG,   RKCUTPPG,   DPPG,       APPGS,     PPGNS,    DCRICWS   TOLPPGIN
      2        100000     0.00192      46.4885    -0.3      0.045     0
CC
CC
* -- APPGFR,    PPGNFR
     334.07    -0.63
CC
CC
*---  ADPPGA,     ADPPGB RESRKFAC,TOLPPGRK
      0.0         0.0     0.2      1e-6
CC
CC
* ---- APPG1,  APPG2,    GAMCPG,  GAMHFPG,  POWNPG
       0.005   0.0001    0.0      0.0       1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
```

```
*----NWELL   IRO   ITIME  NWREL
     2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     1      1       .0001     0.      3      1        1    0
CC
CC WELL NAME
*---- WELNAM
INJECTOR
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     5615.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2    20   1   2       .0001       0.     3     1         1       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      5000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
    1    0.2543  1.   0.  0.     0.   0.008547    0.    0.    0.    0.   0.
0.   0.   0.   400.
    1    0.       0.   0.  0.     0.   0.          0.    0.    0.    0.   0.
0.   0.   0.   0.
     1    0.       0.   0.  0.     0.   0.          0.    0.    0.    0.   0.
0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    14.7
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     5       1       1              0.01   1         10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
 0.0001    0.01     0.1     0.01
```

A-2. Input data for CASE II, Two-phase flow in a sandpack model

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 1.67           PROCESS :  PROFILE CONTROL         *
CC  THICKNESS (FT) :  0.0833     INJ. PRESSURE (PSI) : -            *
CC  WIDTH (FT) : 0.0833          COORDINATES : CARTESIAN            *
CC  POROSITY : 0.386                                                *
CC  GRIDBLOCKS : 80                                                *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
exp2
CC
CC
*----HEADER
Experimental matching # 2, 1-D, 2-phase flow in a sandpack model

***************************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     80    1   1  2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     80*0.020833
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     1*0.0833333
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
     1*0.0833333
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  N
     14   0   6
```

```
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
      5.4
CC
```

```
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       0      0     0      0      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     0.386
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
     27290
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----PERMY(1)
     27290
CC
CC VARIABLE Z-PERMEABILITY
*----PERMZC (MILIDARCY)
     27290
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       0
CC
CC VARIABLE DEPTH (FT)
*----D111
     0.0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     14.7
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
     0.12
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.1342282      0.0
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
```

```
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     0      0    0
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC  S2RWC  S3RWC
     .05    .15    .147
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW     P3RW
     .68    0.48    0.14
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
```

```
*----E1W    E2W      E3W
     6.4    1.6    1.1
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    37    72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
```

```
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.         .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC *---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG, DPPG,        APPGS,   PPGNS,  DCRICWS    TOLPPGIN
      2     10000000    0.0003281     30      -0.3     0.08 20
CC
CC
* -- APPGFR, PPGNFR
       20      -0.2
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
       1      0.00002     0.1   1e-6
CC
CC
* ---- APPG1,APPG2,GAMCPG,GAMHFPG,POWNPG
      0    0    0.0     0.0    1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     1      1       .0001     0.      3      1        1    0
CC
CC WELL NAME
*---- WELNAM
INJECTOR
CC
```

```
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     5615.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW      SWELL  IDIR  IFIRST   ILAST    IPRF
     2    80   1   2       .0001       0.     3     1         1       0
CC
CC WELL NAME
*---- WELNAME
PRODUCER
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      5000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     0.101706  1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.  0.
0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    14.7
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     2.51       1       1            0.1   1         10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
     0.0001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.101706    1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   2000
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
```

```
     3.71     1       1            0.1            1          10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1    1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1       1
CC
CC ID,INJ. RATE AND INJ. COP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.101706    1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.  0.   0.   0.   0.
     1    0.           0.     0.   0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.           0.     0.   0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     5.4    1       1            0.1            1          10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01
```

A-3. Input data for CASE III, Two-phase flow in a coreflood

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) :  0.5              PROCESS :  PROFILE CONTROL      *
CC  THICKNESS (FT) : 0.0833        INJ. PRESSURE (PSI) : -          *
CC  WIDTH (FT) :  0.0833           COORDINATES : CARTESIAN          *
CC  POROSITY :  0.156                                               *
CC  GRIDBLOCKS :   60                                              *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
exp3
CC
CC
*----HEADER
Experimental matching # 3, 1-D, 2-phase flow in a coreflood model

***************************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     60    1   1  2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     60*0.008333
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     1*0.0833333
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
     1*0.0833333
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
```

```
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
 CC

CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF

*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
```

```
      35.656
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       0      0     0      0      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     0.156
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
     192.2
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----PERMY(1)
     192.2
CC
CC VARIABLE Z-PERMEABILITY
*----PERMZC (MILIDARCY)
     192.2
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       0
CC
CC VARIABLE DEPTH (FT)
*----D111
     0.0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRES1
     14.7
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
     0.005
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.1342282      0.0
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
```

```
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
       0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     0      0    0
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC  S2RWC  S3RWC
     .4    .33    .147
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW     P3RW
     .99     0.26     0.14
```

```
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W     E2W      E3W
     4.5     3.6      1.1
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE

*----VIS1   VIS2  TEMPV
     1      37     72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
```

```
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG, DPPG,      APPGS,   PPGNS,  DCRICWS   TOLPPGIN
      2     10000000    0.00033    30      -0.32     0.5     40
CC
CC
* -- APPGFR, PPGNFR
       10      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
       12      0.0002     0.2   1e-6
CC
CC
* ---- APPG1,    APPG2,    GAMCPG,  GAMHFPG, POWNPG
     0.0001     0.0001    10.0     0.0      1.8
CCCC*****************************************************************
CC                                                                 *
CC    WELL DATA                                                    *
CC                                                                 *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     1      1       .0001     0.      3      1        1    0
CC
```

```
CC WELL NAME
*---- WELNAM
INJECTOR
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     5615.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF

     2    60   1   2       .0001       0.     3     1         1       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
     0     0.0      5000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     0.050853  1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    14.7
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     5.406       1       1            0.25   1         10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
    0.0001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.050853    1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   2000
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
    1    0.          0.      0.   0.      0.   0.          0.     0.     0.     0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     28.136     1       1            0.25            1          10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.050853    1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.  0.   0.   0.   0.
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.  0.   0.   0.   0.
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.  0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     35.656     1       1           0.25            1          10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01
```

A-4. Input data for CASE IV, Two-phase flow in a sandpack model with different PPG injection rates

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 3              PROCESS :  PROFILE CONTROL         *
CC  THICKNESS (FT) : 0.082       INJ. PRESSURE (PSI) : -            *
CC  WIDTH (FT) : 0.082           COORDINATES : CARTESIAN            *
CC  POROSITY :  0.364                                               *
CC  GRIDBLOCKS :  40                                               *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
exp4
CC
CC
*----HEADER
Experimental matching # 4, 1-D, 2-phase flow, sandpack model

***************************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     40    1   1  2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     40*0.0749672
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     1*0.082021
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
     1*0.082021
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
```

```
*----N   NTW  NG
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
```

```
      16.024
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       0      0     0      0      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     0.364CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
     27000
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----PERMY(1)
     27000
CC
CC VARIABLE Z-PERMEABILITY
*----PERMZC (MILIDARCY)
     27000
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       0
CC
CC VARIABLE DEPTH (FT)
*----D111
     0.0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     14.7
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
     0.31
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.0336    0.0
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
```

```
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
       0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     0      0    0
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC  S2RWC  S3RWC
     .265    .068    .147
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW     P3RW
     0.72   0.3   0.14
CC
```

```
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W    E2W      E3W
     7.25    2.2    1.1
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    37    72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
```

```
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG,      DPPG,          APPGS,   PPGNS,  DCRICWS    TOLPPGIN
      2     10000000000    0.00059061     35     -0.3       0.05   150
CC
CC
* -- APPGFR,   PPGNFR
      70      -0.25
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      27       0.0009     0.1   1e-6
CC
CC
* ---- APPG1,APPG2,GAMCPG,GAMHFPG,POWNPG
      1e-6   5e-6   0.0     0.0    1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     1      1       .0001     0.      3      1        1    0
CC
CC WELL NAME
```

```
*---- WELNAM
INJECTOR
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     5615.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2    40   1   2       .0001       0.     3     1         1       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      5000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     0.1017062  1.   0.  0.     0.   0.0336       0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.          0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.

     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    14.7
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     0.917       0.2       0.2       0.2       0.2        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
    0.0001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.1017062    1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
    1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     12.691    0.05       0.05       0.05       0.05        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.05085     1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.

     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     13.609     0.05       0.05       0.05       0.05        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
    0.0001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLA
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.152559    1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     13.761    0.05       0.05       0.05       0.05       1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
    0.0001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.20341      .      0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.          0.      0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.      0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     13.853     0.05       0.05       0.05       0.05       1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.254265    1.      0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.          0.      0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.      0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
```

```
     13.93     0.05       0.05       0.05       0.05       1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.3051187    1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   800
     1    0.            0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.            0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     14.006     0.05       0.05       0.05       0.05       1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.355972    1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.    800
     1    0.           0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     14.083    0.2       0.2       0.2       0.2        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
```

```
    0.0001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
      2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.1017062   1.     0.   0.     0.   0.0336      0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     16.024    0.2       0.2       0.2       0.2        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01
```

A-5. Input data for CASE V, Two-phase flow in a parallel sandpack model

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) :  0.66              PROCESS :  PROFILE CONTROL     *
CC  THICKNESS (FT) : 0.14           INJ. PRESSURE (PSI) :  -       *
CC  WIDTH (FT) : 0.07               COORDINATES : CARTESIAN        *
CC  POROSITY : 0.272, 0.375                                         *
CC  GRIDBLOCKS : 80                                                *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
exp5
CC
CC
*----HEADER
Experimental matching # 5, 1-D, 2-phase flow, parallel sandpack model
****************************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
      1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     40    1   2  2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     40*0.0164
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     1*0.07
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
     2*0.07
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
```

```
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
PPG
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  1  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITMP

      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
     0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
      5.23
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
```

```
*----COMPR   PSTAND
     0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       2      2     3      3      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     40*0.2723   40*0.3750
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
     40*6778.2   40*1005.17
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----FACTY
     1
CC
CC VARIABLE Z-PERMEABILITY
*----FACTZ
    0.00001
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       2
CC
CC VARIABLE DEPTH (FT)
*----D111
     0.0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRES1
     14.7
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
     40*0.26   40*0.18
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.17094    0.0
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
```

```
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10OF OIL/WATER INTERFACIAL TENSION
*----XIFT
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     2      2    2
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC
     40*0.45   40*0.10
CC
CC
*----S2RWC
     40*0.09   40*0.32
CC
CC
*----S3RWC
```

```
     40*0.12   40*0.12
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW
     40*0.14   40*0.3
CC
CC
*----P2RW
     40*0.85   40*0.68
CC
CC
*----P3RW
     40*0.35  40*0.35
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1RW
     40*5.2   40*4.2
CC
CC
*----E2RW
     40*1.6  40*2.4
CCCC
*----E3RW
    40*2  40*2
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATUR
*----VIS1   VIS2  TEMPV
     1.0   195    72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
```

```
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.         .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
     0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG,   DPPG,        APPGS,   PPGNS,  DCRICWS   TOLPPGIN
      2     1000000000    0.000262     30      -0.3     0.5       50
CC
CC
* -- APGFR, PPGNFR
      60      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      52     0.0016     0.25   1e-6
```

```
CC
CC
* ---- APPG1,APPG2,GAMCPG,GAMHFPG,POWNPG
      3e-6     2e-6    0.0     0.0    1.8
CC
CC*********************************************************************
CC                                                                    *
CC    WELL DATA                                                       *
CC                                                                    *
CC*********************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      3      2      1      3
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     1      1       .0001     0.      3      1        2    0
CC
CC WELL NAME
*---- WELNAM
INJ
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     5615.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2    40   1   2       .0001       0.     3     1         1       0
CC
CC WELL NAME
*---- WELNAM
PROD_H
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESURE AND RATE

*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
     0     0.0      5000.   0.0     -50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     3    40   1   2       .0001       0.     3     2         2       0
CC
CC WELL NAME
*---- WELNAM
PROD_L
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      5000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     0.0509    1.   0.  0.     0.   0.17094      0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    14.7
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
    3    14.7
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITIG TO OUTPUT FILES

*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     2.86       0.1       0.1       0.1       0.1    1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC.TOLERANCE,MAX.,MIN. COURANT NO.

*----DT      DCLIM     CNMAX   CNMIN
    0.0001    0.01     0.1    0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.0509      1.     0.   0.     0.   0.17094     0.    0.    0.    0.
0.   0.   0.   0.   2000
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     3.05    0.05       0.05       0.05       0.05        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
    0.0001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
```

```
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    0.0509      1.     0.   0.     0.   0.17094     0.    0.    0.    0.
0.   0.   0.   0.   0
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
    5.23     0.05       0.05       0.05       0.05        1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01
```

Appendix B. Input Data for Synthetic Case Simulation

B-1. Input data for the Conduit case I synthetic model

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 375              PROCESS :  PROFILE CONTROL       *
CC  THICKNESS (FT) : 241           INJ. PRESSURE (PSI) :  -         *
CC  WIDTH (FT) :  23.5             COORDINATES : CARTESIAN          *
CC  POROSITY :  0.3                                                 *
CC  GRIDBLOCKS : 6250                                              *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
Conduit Case 1
CC
CC
*----HEADER
Synthetic field case, 1 high perm conduit, 1 injector and 1 producer
PPG treatment
**********************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     25   25   10   2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
   25*15
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
   10  10     10     10     10     10     10     10     10     10     10     1
       10     10     10     10     10     10     10     10     10     10     10
       10     10
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
   2.5 2.5    2.5    2.5    1      2.5    2.5    2.5    2.5    2.5
```

```
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
```

```
CC MAX. SIMULATION TIME (PV)
*---- TMAX
      3.0
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       2      2     3      3      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
2778*0.3  19*0.9  3453*0.3
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
32     33     32     35     34     37     37     30     36     30     32     30
       37     34     33     39     32     33     33     40     40     38     37
       31     30     35     36     33     30     38     40     33     40     37
       40     36     32     31     38     30     34     39     40     40     40
       40     39     34     37     35     32     35     37     37     40     33
       31     32     32     31     31     40     35     35     38     36     40
       30     32     34     32     31     30     38     40     33     35     37
       39     35     38     32     37     37     38     40     33     39     36
       34     32     33     34     37     36     32     32     38     33     40
       38     34     39     35     30     39     38     36     37     36     36
       40     32     39     31     32     35     37     33     32     34     37
       40     37     30     40     39     39     33     33     32     32     33
       32     30     34     40     37     36     37     34     31     30     31
       35     40     32     31     38     39     40     32     35     32     34
       40     38     33     37     35     32     31     40     34     39     32
       40     37     32     33     33     35     34     31     39     34     36
       30     32     35     30     31     37     35     37     33     37     39
       38     37     34     34     37     32     30     38     36     36     32
       39     34     37     37     36     32     34     32     37     31     36
       38     39     31     31     35     38     32     33     31     31     36
       33     32     32     34     39     36     33     34     35     30     36
       39     34     32     31     37     36     39     37     35     32     37
       32     37     33     38     37     31     37     34     39     39     30
       37     30     40     36     33     31     35     36     30     37     35
       40     39     33     38     34     34     38     31     40     37     35
       34     35     40     32     35     35     34     30     33     40     37
       40     31     33     36     31     36     33     30     38     40     38
       36     40     31     39     34     30     38     31     34     40     39
       38     30     34     31     39     32     30     37     32     30     30
       35     38     40     40     36     33     34     30     33     38     36
       36     35     35     34     39     30     37     39     35     35     33
       37     30     33     32     30     36     36     34     39     39     37
       36     31     36     40     39     38     30     36     36     40     38
       39     31     34     30     37     37     31     33     36     35     39
       35     33     33     33     35     36     38     37     39     30     32
       34     34     37     30     39     38     36     31     30     36     38
       32     34     37     34     31     36     40     31     30     37     37
       32     30     30     37     36     37     34     30     38     40     32
       40     36     36     34     31     38     36     30     34     37     33
       40     32     30     31     34     39     30     39     35     35     30
       37     34     33     35     35     37     37     32     35     40     34
       34     37     34     35     39     36     31     37     35     30     40
```

	38	34	32	33	30	33	30	34	32	36	36
	40	36	31	38	38	37	38	33	31	30	37
	37	36	38	38	40	38	39	39	32	30	35
	37	34	36	30	36	31	32	30	30	34	35
	38	32	38	39	36	34	39	38	33	35	35
	35	39	33	36	33	31	34	35	40	34	40
	38	37	39	39	34	31	38	37	38	39	35
	35	35	33	39	30	34	33	35	32	38	34
	39	32	30	40	39	33	33	33	38	40	40
	31	38	31	30	32	38	39	36	31	33	35
	31	31	39	39	34	40	39	31	38	32	35
	32	37	40	36	33	36	32	40	33	38	40
	40	38	33	37	37	36	34	31	36	39	31
	36	32	35	38	32	33	33	36	32	33	38
	40	38	37	39	37	37	32	31			
45	45	41	44	44	45	45	40	44	43	41	43
	44	42	42	41	43	42	41	45	43	40	43
	42	44	41	42	41	41	41	42	41	43	40
	42	44	43	41	42	43	44	41	42	40	45
	45	43	41	44	44	44	44	45	41	42	43
	41	45	43	42	40	40	40	42	45	44	43
	45	40	44	41	42	44	44	40	41	41	43
	42	40	40	40	40	44	40	43	42	42	45
	42	44	41	42	43	40	43	43	44	43	45
	45	43	41	40	42	41	40	43	44	45	45
	45	44	43	40	42	41	41	42	45	40	42
	43	42	43	41	40	45	40	42	42	41	42
	45	43	42	43	42	44	43	40	40	42	45
	41	44	44	45	43	44	42	44	42	45	45
	40	44	40	40	42	42	43	44	40	43	40
	42	42	42	45	42	44	42	45	40	41	41
	42	42	41	43	41	44	44	44	45	45	44
	41	44	40	41	44	44	44	42	42	42	43
	43	45	43	44	45	44	41	45	45	41	44
	44	42	40	40	45	41	45	43	45	40	43
	43	44	41	41	40	41	43	44	44	45	44
	45	41	44	45	42	45	41	42	44	41	45
	43	40	45	40	43	41	44	41	45	42	45
	44	41	44	41	42	42	42	40	45	42	40
	40	45	43	45	42	45	41	44	42	43	42
	43	41	40	45	44	45	45	42	44	45	42
	44	42	41	41	41	44	42	41	41	42	43
	45	45	43	42	42	42	40	44	40	40	44
	45	45	43	40	40	41	44	43	42	42	41
	44	45	40	42	42	43	42	42	43	42	44
	42	45	44	41	43	42	42	44	44	41	45
	44	44	41	43	42	41	43	42	43	44	40
	41	43	43	43	43	42	40	43	43	44	43
	43	41	40	45	44	45	43	45	43	40	43
	40	40	44	43	45	42	40	45	42	42	42
	41	44	42	44	41	43	45	45	41	41	44
	44	41	43	41	45	40	43	43	45	41	40
	40	40	42	43	40	42	45	41	40	43	41
	42	44	45	40	41	42	40	45	43	43	41
	43	41	45	44	43	41	43	45	45	45	42
	41	40	44	44	44	45	45	45	45	45	40
	43	44	41	45	43	40	42	43	44	41	43
	45	43	42	41	44	41	43	40	40	45	42
	43	42	42	41	41	42	45	42	41	44	45
	43	44	43	41	40	42	45	42	41	44	44

	43	40	43	41	41	41	40	43	45	42	40
	42	43	42	42	42	40	44	40	44	40	45
	44	45	42	43	42	42	40	41	44	45	41
	45	44	44	42	41	42	41	41	40	42	45
	41	44	43	43	41	41	43	43	40	45	44
	45	41	41	41	40	45	42	43	40	43	44
	40	45	40	41	41	41	45	45	42	43	45
	42	45	44	42	44	45	41	45	43	44	45
	43	44	43	45	44	40	43	44	41	45	40
	40	43	40	45	45	40	43	41	42	44	41
	45	42	45	42	45	44	42	41	40	42	43
	41	43	44	42	44	42	44	45			
45	47	45	48	47	48	49	48	45	47	50	46
	46	49	45	49	49	50	50	50	49	50	48
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	60	62	56	56	64	60	55	65	61	55	59
	64	65	55	60	57	62	62	58	65	60	58
	60	60	57	58	57	63	56	57	60	58	65
	63	57	57	63	63	58	55	64	64	58	56

	64	65	58	60	61	60	65	62	63	55	60
	58	55	65	56	65	61	56	65	60	60	63
	60	57	58	58	57	55	56	60	57	65	57
	59	62	65	65	64	59	60	55	65	58	58
	56	60	63	61	55	59	65	56	65	56	55
	56	55	57	56	61	61	55	58	62	63	55
	56	58	59	61	59	59	65	55	63	60	62
	55	62	59	61	59	60	56	58	59	65	65
	65	57	57	61	61	55	59	64	64	58	64
	65	63	59	56	55	55	58	57	61	57	65
	64	55	56	57	55	56	64	64	60	58	62
	59	59	60	57	60	63	55	60	56	64	60
	63	64	58	64	55	64	55	63	57	61	58
	63	58	56	57	62	65	59	56	64	60	57
	64	62	62	64	60	61	56	57	61	62	59
	56	65	61	63	57	61	57	57	56	56	56
	60	55	56	60	65	62	62	55	58	59	57
	55	62	61	60	63	58	62	55	60	63	55
	64	58	62	58	65	56	64	62	55	58	65
	58	57	56	63	62	63	64	56	60	60	60
	62	60	62	58	55	62	56	63	59	56	58
	58	56	57	63	60	65	62	60	60	57	60
	55	61	59	65	55	55	61	64	55	56	56
	62	55	58	61	63	57	56	59	61	55	59
	62	57	64	57	63	55	59	57	62	58	63
	56	56	56	62	63	64	64	64	65	64	60
	61	60	57	64	61	65	56	60	63	55	58
	57	56	60	55	60	58	56	60	65	63	58
	63	58	58	59	56	60	62	58	61	56	64
	62	56	63	56	61	57	65	58	59	58	58
	60	63	63	56	57	59	63	58	62	60	60
	65	59	62	60	63	57	55	59	63	60	63
	56	58	58	63	64	56	63	61	55	61	56
	61	60	61	58	60	60	64	64	57	60	59
	64	59	61	61	62	58	61	62	57	63	65
	63	65	64	65	64	64	63	62	65	57	64
	60	58	55	58	59	57	60	61	56	61	55
	55	55	63	57	62	56	57	63	63	65	61
	60	63	59	59	59	65	64	58	61	61	56
	55	57	63	63	65	65	55	61	64	64	56
	55	64	64	60	56	64	64	65	61	56	55
	62	58	65	57	59	64	57	57	58	57	59
	65	61	58	57	64	57	58	58	59	64	62
	61	55	60	64	64	60	59	65	58	61	59
	61	60	57	63	64	61	65	63	57	63	65
	64	61	56	60	60	63	62	55	55	61	57
	59	62	63	59	57	59	60	58	64	55	64
	57	57	60	57	63	64	65	56	63	63	62
	63	64	59	64	57	56	65	59	56	60	60
	64	65	58	60	60	60	64	55	57	60	63
	56	58	61	63	58	58	56	64			
56	69	56	55	57	65	62	59	50	68	64	64
	64	59	59	62	68	69	69	52	53	59	70
	69	58	70	56	61	50	58	69	70	50	69
	69	56	61	56	57	59	69	56	54	63	57
	62	51	70	56	55	60	66	70	63	62	70
	57	70	67	56	65	57	62	52	59	65	66
	64	65	67	52	59	65	61	56	69	54	51
	57	61	64	53	68	57	55	60	64	67	66
	57	66	70	67	67	69	50	60	51	70	69

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      64     55     59     53     66     56     65     66     50     53     55
      58     52     69     59     70     60     55     52     60     62     64
      57     52     50     53     65     70     62     59     65     54     61
      62     59     55     62     51     63     69     59     69     55     61
      52     69     62     60     70     53     64     52     60     62     59
      61     52     66     68     61     69     67     70     70     62     60
      55     57     59     70     50     62     62     61     70     61     54
      60     50     61     51     63     60     66     61     50     56     59
      51     61     51     56     67     59     55     61     67     58     56
      61     68     57     69     64     51     63     58     57     67     53
      62     61     61     66     50     61     58     50     67     53     52
      69     64     60     53     68     67     68     59     62     54     63
      63     61     54     59     62     70     57     58     50     60     50
      66     50     63     54     63     65     54     62     55     64     51
      61     52     61     65     50     69     64     60     67     62     59
      53     67     62     57     56     56     59     61     60     51     56
      63     66     54     50     52     56     61     70     66     69     66
      60     56     53     54     50     52     52     58     53     58     61
      51     66     55     57     60     69     65     59     55     56     53
      53     65     50     62     68     59     51     51     63     66     56
      51     60     58     57     56     58     56     57     55     65     53
      51     50     60     62     61     66     59     56     53     62     61
      50     59     62     52     54     57     53     53     60     56     55
      60     70     65     53     57     62     62     57     66     69     55
      58     69     63     65     57     54     54     56     67     63     50
      66     57     69     63     65     51     60     64     61     63     64
      70     63     66     61     60     65     65     61     56     64     53
      59     56     68     70     66     67     57     67     65     64     60
      61     59     56     66     52     55     67     62     52     53     52
      62     55     54     56     57     50     69     52     51     51     68
      58     68     59     57     69     53     66     50     53     65     56
      67     62     56     56     51     56     57     70     64     52     57
      70     67     53     51     53     63     64     53     55     63     52
      64     63     60     69     51     64     60     58     69     67     69
      60     56     51     51     65     65     50     50     64     55     60
      57     68     51     64     62     55     68     66     70     67     60
      50     57     52     66     61     66     60     59     66     58     65
      66     65     62     57     58     70     50     63     53     50     70
      54     69     65     60     68     60     65     62     69     51     52
      50     64     60     54     68     67     54     61     56     68     58
      66     59     70     65     65     65     68     68     59     60     53
      54     62     67     66     50     57     64     60     67     54     55
      67     62     68     57     69     61     52     58     64     68     69
      61     55     61     67     59     66     50     65     60     64     58
      53     57     64     50     56     67     69     57     64     61     61
      63     65     58     66     67     66     59     54     52     69     59
      52     63     67     55     64     69     70     5      70     54     62
      62     65     61     64     53     50     61     60
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----FACTY
     1
CC
CC VARIABLE Z-PERMEABILITY
*----FACTZ
     0.1
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       2
```

```
CC
CC VARIABLE DEPTH (FT)
*----D111
     5000
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     2000CC
CC CONSTANT INITIAL WATER SATURATION
*----SW
2778*0.31  19*0.2  3453*0.31CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.1342282      0.0
CC
CC*****************************************************************
CC                                                               *
CC    PHYSICAL PROPERTY DATA                                     *
CC                                                               *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  ETA8

     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
    20       .0001

CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
```

```
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     2      2    2
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC
2778*0.31  19*0.2  3453*0.31
CC
CC
*----S2RWC
2778*0.22  19*0.17  3453*0.22
CC
CC
*----S3RWC
2778*0.31  19*0.2  3453*0.31
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW
2778*0.5   19*0.92  3453*0.5
CC
CC
*----P2RW
2778*0.72   19*0.92  3453*0.72
CC
CC
*----P3RW
2778*0.5   19*0.92  3453*0.5
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W
2778*3   19*1.2  3453*3
CC
CC
*---E2W
2778*1.9   19*1.1  3453*1.9
CC
CC
*---E3W
2778*3   19*1.2  3453*3
CC
```

```
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    37    72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
    0.0     0.0      0.0   0.000865    4.153

CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG

*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
  62.899  49.857  62.399  49.824  0  2

CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
      0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH CMPONENT IN PHASE 1 (D(KC),KC=1,N)

*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
```

```
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC *---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG,   DPPG,         APPGS,   PPGNS,  DCRICWS   TOLPPGIN
      2     1000000000    0.0003281     10      -0.3     0.5       40
CC
CC
* -- APPGFR, PPGNFR
       100      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      5       0.02     0.1   1e-6
CC
CC
* ---- APPG1,APPG2,GAMCPG,GAMHFPG,POWNPG
      1e-6    1e-6    0.0     0.0    1.8
CC
CC***************************************************************
CC                                                              *
CC    WELL DATA                                                 *
CC                                                              *
CC***************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    1     13      1       0.4     0.      3      2       7    0
CC
CC WELL NAME
*---- WELNAM
```

```
INJECTOR1
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2    25   13    2       0.4       0.     3     2         7       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
    1     3000       1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.            0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.            0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    200CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RST
    1.0       0.1       0.1             0.1   0.1         5

CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
    0.001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    3000        1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.  800.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     2.0     0.1       0.1            0.1            0.1          5
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
    0.001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    3000        1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
    3.0     0.1       0.1            0.1            0.1          5
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.001   0.01          0.1   0.01
```

B-2. Input data for the Conduit case II synthetic model

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) :  627             PROCESS :  PROFILE CONTROL       *
CC  THICKNESS (FT) : 19            INJ. PRESSURE (PSI) :  -         *
CC  WIDTH (FT) :   625             COORDINATES : CARTESIAN          *
CC  POROSITY :   0.3                                                *
CC  GRIDBLOCKS :  6250                                             *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
Conduit Case 2
CC
CC
*----HEADER
Synthetic field case, 1 high perm conduit, 1 injector and 4 producers
PPG treatment
**********************************************************************
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT

     25   25   10   2       0
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX(I)
     25*25
CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     28       28     28     28     28     28     28     28     28     28     28
       5      1      5      28     28     28     28     28     28     28     28
       28     28     28
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
 2     2      2      2      1      2      2      2      2      2
CC
```

```
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OI
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
```

```
*---- TMAX
      3.0
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       2      2     3      3      0     0      0
CC
CC VARIABE POROSITY

*----PORC1
2803*0.3     19*0.9   3428*0.3   CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
32     33     32     35     34     37     37     30     36     30     32     30
       37     34     33     39     32     33     33     40     40     38     37
       31     30     35     36     33     30     38     40     33     40     37
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       40     39     34     37     35     32     35     37     37     40     33
       31     32     32     31     31     40     35     35     38     36     40
       30     32     34     32     31     30     38     40     33     35     37
       39     35     38     32     37     37     38     40     33     39     36
       34     32     33     34     37     36     32     32     38     33     40
       38     34     39     35     30     39     38     36     37     36     36
       40     32     39     31     32     35     37     33     32     34     37
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       39     34     37     37     36     32     34     32     37     31     36
       38     39     31     31     35     38     32     33     31     31     36
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CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----FACTY
     1
CC
CC VARIABLE Z-PERMEABILITY
*----FACTZ
     0.1
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       2
```

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CC
CC VARIABLE DEPTH (FT)
*----D111
    5000

CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     2000
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
2803*0.31    19*0.2   3428*0.31
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.1342282      0.0
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
       .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL

*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
       0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
```

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     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     2      2    2
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC
2803*0.3     19*0.9   3428*0.3
CC
CC
*----S2RWC
2803*0.22    19*0.17   3428*0.22
CC
CC
*----S3RWC
2803*0.3     19*0.9   3428*0.3
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW 2803*0.5  19*0.92   3428*0.5
CC
CC
*----P2RW
2803*0.72    19*0.92   3428*0.72
CC
CC
*----P3RW
2803*0.5     19*0.92   3428*0.5
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W
2803*3 19*1.2   3428*3
CC
CC
*---E2W
2803*1.9     19*1.1   3428*1.9
CC
CC
*---E3W
2803*3 19*1.2   3428*3
```

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CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    37    72.5
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8 IDEN

   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
```

```
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS

*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk

     0.         .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG,   DPPG,        APPGS,   PPGNS,  DCRICWS   TOLPPGIN
      2     1000000000    0.0003281     10      -0.3     0.5       40
CC
CC
* -- APPGFR, PPGNFR
       500      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      0       0     0.1   1e-6
CC
CC
* ---- APPG1,APPG2,GAMCPG,GAMHFPG,POWNPG
      0.001     0.001    0.0     0.0    1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELLRADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      5      2      1      5
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    13     13      1       0.4     0.      3      2       7    0
CC
CC WELL NAME
```

```
*---- WELNAM
INJECTOR1
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
    2    1   13    2       0.4       0.     3     2         7       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     3    25   13    2       0.4       0.     3     2         7       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER3
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     4    13   1    2       0.4       0.     3     2         7       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER3
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
     0     0.0      10000.   0.0     -50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     5    13   25    2       0.4       0.     3     2         7       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER4
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     5000      1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
     1     0.         0.   0.  0.      0.   0.           0.    0.    0.    0.  0.
0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
    2    500
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
    3    500
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
    4    500
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     5    500
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     0.5       0.1       0.1             0.1   0.1         5
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
----DT      DCLIM     CNMAX   CNMIN

    0.001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2  2  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
    1    5000        1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.  1500.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     1.5    0.1       0.1            0.1            0.1          5
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
    0.001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2  2  2
```

```
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    5000        1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
    3.0     0.1       0.1            0.1            0.1          5
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM           CNMAX   CNMIN
     0.001   0.01           0.1   0.01
```

B-3. The impact of having the conduit in the synthetic models

Conduit case I

Adding a conduit into a reservoir model resulted in an waterflood oil recovery reduction as seen in Figure B-1. The waterflood recovery from the model without the conduit was 49.31% while the recovery from the model with the conduit was 47.93%. This was due to the fact that water broke through to the producer more rapidly along the conduit. Even though the layer that containing the conduit took up only 4% of the total thickness and the volume occupied by the conduit accounted for merely 0.013% of the total volume, its effect on waterflood recovery was as significant as 1.38% reduction.

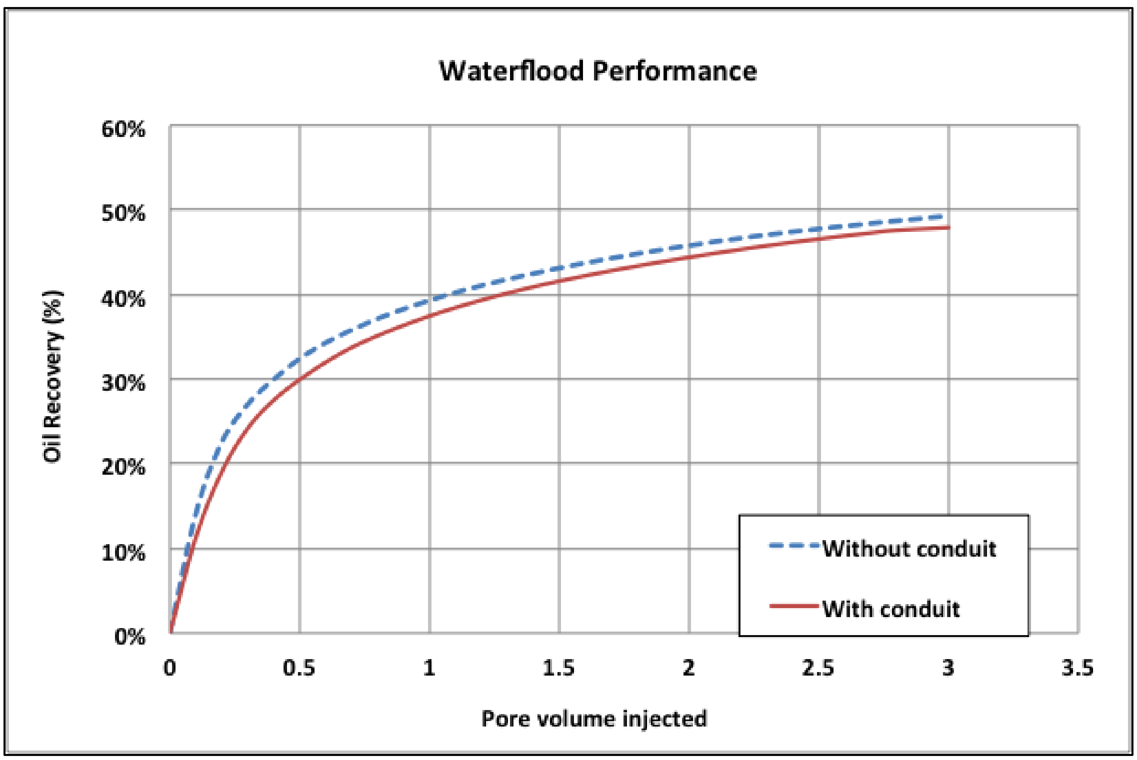

Figure B - 1. Comparison of the waterflood performance of a reservoir with and without conduit, Conduit case I

Conduit case II

Figure B-2 shows the comparison of the oil recoveries from waterflooding the synthetic model with and without the conduit for the Conduit case II study. The waterflood recovery from the model without the conduit was 41.85% while the recovery from the model with the conduit was 40.82%. The conduit's impact on waterflood recovery in this case was 1.03% reduction despite the fact that the volume occupied by the conduit was as insignificant as 0.006% of the total volume. In order to allow a better sweep efficiency and optimize the production from all four producers, a PPG treatment was required to block the conduit channel and divert the water equally among the four producers.

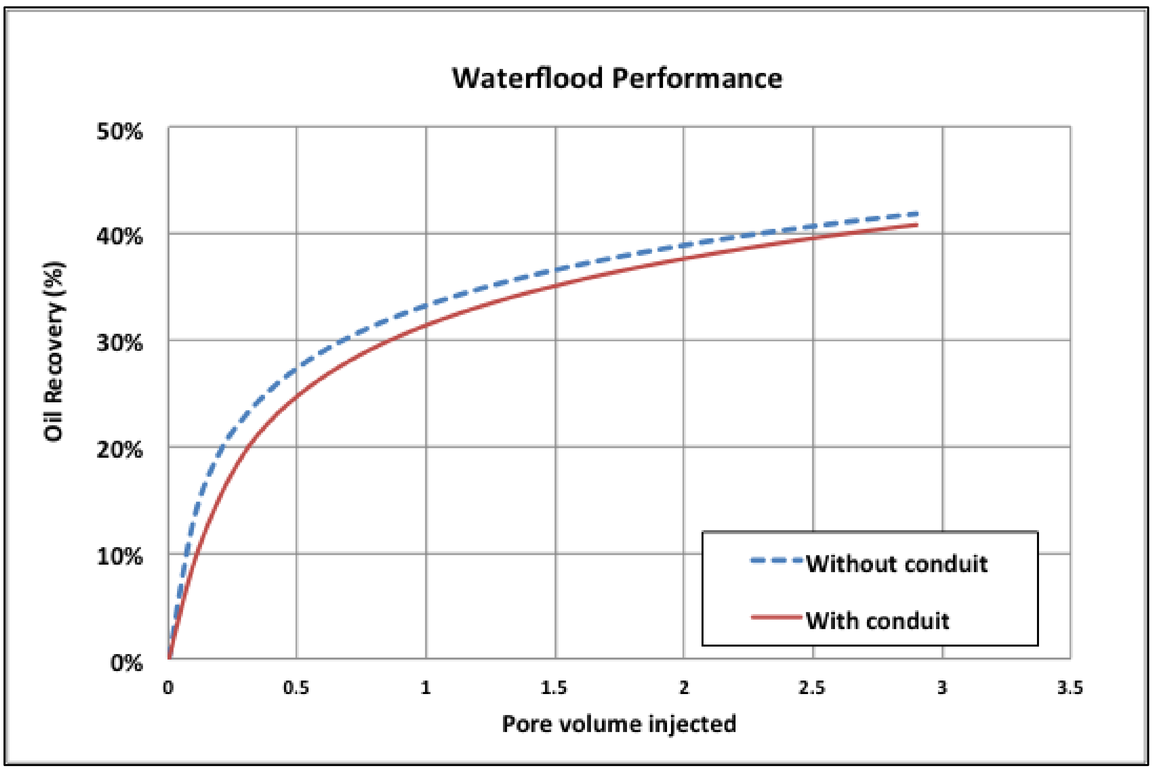

Figure B - 2. Comparison of the waterflood performance of a reservoir with and without conduit, Conduit case II

Appendix C. Input Data for Field Case Simulation

C-1. Input data for field case I, gel type comparison (Gel type = PPG)

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 3225              PROCESS :  PROFILE CONTROL      *
CC  THICKNESS (FT) : 37           INJ. PRESSURE (PSI) :  -          *
CC  WIDTH (FT) :  3525             COORDINATES : CARTESIAN          *
CC  POROSITY :  variable                                            *
CC  GRIDBLOCKS : 43x47x19 (38399)                                  *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
Field1
CC
CC
*----HEADER
Minas field
Modified from CDG Flood case of Abdulmaki Mazen Ramzi, 2012
Field optimization - Gel type comparison
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT ICOORD ITREAC ITC IENG
      1     2    3      0      1      0      0   0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX    NY  NZ  IDXYZ  IUNIT
     43    47  19  2       0
CC
CC CONSTANT GRID BLOCK SIZE IN X, Y, AND Z  (in ft)
*----DX
     43*75
CC
CC  CONSTANT GRID BLOCK SIZE IN X, Y, AND Z  (in ft)
*----DY
     47*75
CC
CC
```

```
*----DZ  (this is mean from NET from ecl2gocad) total thickness is about 68 ft
     2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 1
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW   NG
     14  0     6
CC
CC  All species must be present even for standard waterflood.
*---- species name
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
      1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC ICUMTM=0==>TIME PRINTING;istop=1==>PV SPEC
CC FLAGS FOR PV OR DAYS
*----ICUMTM  ISTOP
     1       1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
      1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL IPTEMP
     1      1     1      1     0
CC  ICKL is phase conc.  (K is component and L is phase)
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----ICKL IVIS IPER ICNM ICSE
     0    1    0    0   0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----IADS  IVEL IRKF IPHSE
     0    0    1    0
CC
CC*****************************************************************
CC                                                                *
CC    RESERVOIR PROPERTIES                                        *
CC                                                                *
CC*****************************************************************
```

```
CC
CC
CC MAX. SIMULATION TIME
*---- TMAX
      7.3
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR      PSTAND
     0.000008   14.7
CC  Porosity Values For Each Grid Input Given Through Include Files
CC  FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRANZ  INTG
     4     4      4      4       0     0       0
CC Depth To The Top Layer Input Given Through Include Files
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
     4       1       0
CC
CC
*----PINIT    HINIT
     550.     1965.77185
CC
CC WATER SATURATION
*----SWI
     0.2
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.0513    0.0
CC
CC*******************************************************************
CC                                                                  *
CC PHYSICAL PROPERTY DATA                                           *
CC                                                                  *
CC*******************************************************************
CC
CC
CC OIL CONC. AT PLAIT POINT FOR TYPE II(+) AND TYPE II(-), CMC (do not change)
*---- EPSME
      0.0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.0    0.055  0      0.035  0.     0.055
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1(7) AND ALCOHOL 2 (8)
*----CSEL7     CSEU7     CSEL8  CSEU8
     0.5       0.85      0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0     0     0.0
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.0      0      0.      0.
```

```
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1  (leave as is)
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671    1.79   48   35.31  0.222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- ift
     1
CC
CC INTERFACIAL TENSION PARAMETERS
*----CHUH  AHUH
     0.3   10.
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.48
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     2      2000.      75000.     365.
CC
CC
*----iperm     IRTYPE
     0          0
CC RESIDUAL SATURATION FOR EACH PHASE INPUT GIVEN THROUGH INCLUDE FILES
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     4      0    0
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW  P3RW
     0.30   0.7   0.30
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W   E2W  E3W
     2     2    2
CC
CC  RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----S1RC(=SWIR)  S2RC(=SORCHEM)  S3RC(SMER=SWIR)
     0.0001    0.0001   0.0001
CC
CC ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----P1RC P2RC P3RC
     1.    1.    1.
CC
CC REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----E13CW  E23C E31C
     1    1    1
CC
CC WATER AND OIL VISCOSITY at reference temperature, RESERVOIR TEMPERATURE
(leave zero)
*----VIS1   VIS2  TEMPV
```

```
     0.37    3.4     0.
CC
CC MICROEMULSION VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
       .1     2.5     0.1       0.1     0.1
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1      AP2     AP3
    45        625     1000
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SSLOPE
     1.    .01   -0.377
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY (50% shear ~ 10 cP)
*----GAMMAC  GAMHF  POWN   IPMOD  ISHEAR   RWEFF  GAMHF2  IWREATH
      4       30    1.8     0       1       0.4   0.0    1
CC
CC WREATH CORRELATION PARAMETERS
*----WREATHM  WREATHB  WREATHN  WREATHT
     4.7      0.18     0.48     1.0
CC
CC FLAG FOR POLYMER (4) PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4   BRK    CRK    rkcut
     1      1.    1       100   0.04      10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2  DEN3 DEN7 DEN8 IDEN
     .433  .377  .433 .346  0.  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      1
CC
CC  FVF FOR PHASE 1,2,3
*-----(FVF(L),L=1,NPHAS)
      1    1.083    1
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.000003   0.00001        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0     0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
     0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9) D(10) D(1
     0.   0.   0.   0.    0.  0.  8*0.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9)  D(10)  D(11)
```

```
     0.   0.   0.   0.   0.   0.  8*0.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9) D(10)  D(11)
     0.   0.   0.   0.   0.   0.   8*0.
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY (ft) OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     4             0.4
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     4             0.4
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     4            0.4
CC   Polymer (7 microg/g), surf. (0.3 mg/g)
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31  AD32  B3D    AD41   AD42  B4D      iadk   iads1   fads refk(mD)
     0.125     0.0  1000.  1   0.    100.       0       0     0   0.
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT MW (needed for cation
exch)
*----QV      XKC   XKS  EQW
    0.0     0.0   0.0  429.
CC
CC*---  KGOPT
      4
CC
CC
* -- IRKPPG,RKCUTPPG,   DPPG,         APPGS,   PPGNS,  DCRICWS   TOLPPGIN
      2     1000000000    0.0003281     8      -0.3     0.5       50
CC
CC
* -- APPGFR,    PPGNFR
       100      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      0        0       0.1      1e-6
CC
CC
* ---- APPG1,    APPG2,  GAMCPG, GAMHFPG, POWNPG
      1.5e-6     1e-6    0.0     0.0      1.8
CC
CC*******************************************************************
CC                                                                  *
CC  WELL DATA                                                       *
CC                                                                  *
CC*******************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWELR
      17      2      1     17
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     1   16     13     1     0.4     0      3     1        19       0
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CC
CC WELL NAME
*---- WELNAM
S1_I1
CC Maximum allowable rate of 2500b/d= 44916.8 cubic feet per day
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
      2   30   13  1        0.4    0      3      1       19        0
CC
CC WELL NAME
*---- WELNAM
S1_I2
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     3   36   25  1       0.4    0      3      1       19        0
CC
CC WELL NAME
*---- WELNAM
S1_I3
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     4   30   37    1      0.4    0      3      1       19        0
CC
CC WELL NAME
*---- WELNAM
S1_I4
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     5   16    37     1     0.4    0      3      1      19        0
CC
CC WELL NAME
*---- WELNAM
S1_I5
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     6   10   25    1     0.4     0      3      1       19         0
```

```
CC
CC WELL NAME
*---- WELNAM
S1_I6
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
      7   10     5     1     0.4     0      3      1       19         0
CC
CC WELL NAME
*---- WELNAM
S1_I7
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     8   36    5     1     0.4       0      3      1       19      0
CC
CC WELL NAME
*---- WELNAM
S1_I8
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     9   36  44     1     0.4     0      3      1       19            0
CC
CC WELL NAME
*---- WELNAM
S1_I9
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     10   10    44     1     0.4     0      3      1       19     0
CC
CC WELL NAME
*---- WELNAM
S1_I10
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0    1300.0  0.0     84219
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     11  22   25    2      0.4    0      3      1      19     0
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CC
CC WELL NAME
*---- WELNAM
S1_P1
CC   DW, max 10000 bbls/d
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1300.   0.0     -56146.0
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     12  22   5     2       0.4    0      3      1       19      0
CC
CC WELL NAME
*---- WELNAM
S1_P2
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0    -28073
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     13  40   13     2       0.4    0      3      1       19     0
CC
CC WELL NAME
*---- WELNAM
S1_P3
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0     -28073
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     14  40   37    2      0.4    0      3      1       19      0
CC
CC WELL NAME
*---- WELNAM
S1_P4
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0     -28073
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     15  22   44    2      0.4    0      3      1       19        0
CC
CC WELL NAME
*---- WELNAM
S1_P5
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0    -28073
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     16  4    37    2       0.4    0      3      1       19      0
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CC
CC WELL NAME
*---- WELNAM
S1_P6
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0     -28073
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     17   4   13     2       0.4    0      3      1      19         0
CC
CC WELL NAME
*---- WELNAM
S1_P7
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX  QTMIN   QTMAX
     0       300.0      1400.   0.0     -28073
CC
CC
*----ID   QI    C
     1  44916.8     1.    0.   0.    0.    0.05130  0.     2*0   4*0  2*0
     1    0.        0.    0.   0.    0.    0.       0.     6*0   2*0
     1    0.        0.    0.   0.    0.    0.       0.     6*0   2*0
CC
CC
*----ID   QI    C
     2   44916.8   1.    0.   0.    0.    0.05130   0.     2*0   4*0  2*0
     2    0.        0.    0.   0.    0.    0.        0.     6*0   2*0
     2    0.        0.    0.   0.    0.    0.        0.     6*0   2*0
CC
CC
*----ID   QI    C
     3  44916.8     1.    0.   0.    0.    0.05130 0.     2*0   4*0 2*0
     3    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
     3    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     4  44916.8     1.    0.   0.    0.    0.05130 0.     2*0   4*0  2*0
     4    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
     4    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     5  44916.8     1.    0.   0.    0.    0.05130 0.     2*0   4*0  2*0
     5    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
     5    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     6  44916.8     1.    0.   0.    0.    0.05130 0.     2*0  4*0 2*0
     6    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
     6    0.        0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     7  22458.4     1.    0.   0.    0.    0.05130 0.     2*0  4*0 2*0
```

```
     7    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
     7    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     8  22458.4     1.    0.   0.    0.    0.05130 0.     2*0  4*0 2*0
     8    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
     8    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     9  22458.4     1.    0.   0.    0.    0.05130 0.     2*0  4*0  2*0
     9    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
     9    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     10  22458.4     1.    0.   0.    0.    0.05130 0.     2*0  4*0  2*0
     10    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
     10    0.         0.    0.   0.    0.    0.      0.     6*0   2*0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     11         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     12         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     13         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     14         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     15         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     16         300.0
CC
CC   Pressure constrained producer
*----WELL ID   PWF
     17         300.0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
(3.7.8)
*----TINJ      CUMPR1  CUMHI2  WRHPV(HIST) WRPRF(PLOT) RSTC
    5         4.9     4.9     0.2          0.5        4.9
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT              DCLIM     CNMAX   CNMIN
     0.00001         0.001     0.2     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITSTEP IFLAG
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      2   1     10*1  7*2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID - SP FLOOD INTO 10 INJECTORS
*----NWEL2   ID
     10       1 2 3 4 5 6 7 8 9 10
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     1    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     1    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
     1    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     2    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     2    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
     2    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
CC
CC
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     3    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     3    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
     3    0.          0.    0.   0.    0.    0.      0.         6*0   2*0
CC
CC
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     4    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     4    0.          0.     0.   0.    0.    0.      0.         6*0   2*0
     4    0.          0.     0.   0.    0.    0.      0.         6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     5    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     5    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
     5    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     6    14036.5     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     6    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
     6    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     7    7018.25   1.    0.   0.    0.    0.7116  0   0  6*0  2000
     7    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
     7    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     8   7018.25     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     8    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
     8    0.          0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
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     9   7018.25     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     9    0.        0.    0.   0.    0.    0.      0.         6*0  2*0
     9    0.        0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     10  7018.25     1.    0.   0.    0.    0.7116  0  0  6*0  2000
     10    0.        0.    0.   0.    0.    0.      0.         6*0  2*0
     10    0.        0.    0.   0.    0.    0.      0.         6*0  2*0
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
(3.7.8)
*----TINJ    CUMPR1  CUMHI2 WRHPV(HIST) WRPRF(PLOT) RSTC
     5.3     0.01    0.1   0.01        0.1        0.05
CC CDG Inj.
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT             DCLIM     CNMAX   CNMIN
     0.00001       0.005     0.05   0.001
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITIME IFLAG
       2   1     10*1  7*2
CC
CC NUMBER OF WELLS changes IN LOCATION OR SKIN OR PWF
*----NWEL1
      0
CC
CC NUMBER OF WELLS WITH RATE changes, id
*----NWEL2   Id
     10      1 2 3 4 5 6 7 8 9 10
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     1  14036.5     1.    0.   0.    0.   0.0513   0.       0     7*0
     1    0.        0.    0.   0.    0.    0.      0.       6*0   2*0
     1    0.        0.    0.   0.    0.    0.      0.       6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     2  14036.5     1.    0.   0.    0.0  0.0513   0.        0     7*0
     2    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
     2    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     3  14036.5     1.    0.   0.    0.   0.0513   0.        0    7*0
     3    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
     3    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     4  14036.5     1.    0.   0.    0.   0.0513   0.        0     7*0
     4    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
     4    0.        0.    0.   0.    0.    0.      0.        6*0   2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     5  14036.5     1.    0.   0.    0.   0.0513   0.        0    7*0
     5    0.        0.    0.   0.    0.    0.      0.        6*0  2*0
     5    0.        0.    0.   0.    0.    0.      0.        6*0  2*0
```

```
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     6  14036.5     1.    0.   0.    0.0  0.0513   0.        0    7*0
     6    0.        0.    0.   0.    0.    0.      0.        6*0  2*0
     6    0.        0.    0.   0.    0.    0.      0.        6*0  2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     7    7018.25        1.    0.   0.    0.0  0.0513   0.        0      7*0
     7    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
     7    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     8    7018.25        1.    0.   0.    0.0  0.0513   0.        0      7*0
     8    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
     8    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     9    7018.25        1.    0.   0.    0.0  0.0513   0.        0      7*0
     9    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
     9    0.             0.    0.   0.    0.    0.      0.        6*0    2*0
CC
CC id,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE(L=1,3)
*----id  QI(M,L)  C(M,KC,L) (need to keep 2nd and 3rd lines for oil and ME)
     10    7018.25        1.    0.   0.    0.0  0.0513   0.        0    7*0
     10    0.             0.    0.   0.    0.    0.      0.        6*0  2*0
     10    0.             0.    0.   0.    0.    0.      0.        6*0  2*0
CC post flush formation water injection
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
(3.7.8)
*----TINJ      CUMPR1  CUMHI2 WRHPV(HIST) WRPRF(PLOT) RSTC
     7.3       0.5    0.5   0.01        0.3        0.3
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps
*----DT              DCLIM     CNMAX   CNMIN
     0.000001       0.001     0.05   0.001
```

C-2. Input data for Field case II, PPG concentration optimization (PPG concentration = 2000 PPM)

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 623.2             PROCESS :  PROFILE CONTROL      *
CC  THICKNESS (FT) : 40             INJ. PRESSURE (PSI) :  -        *
CC  WIDTH (FT) :  623.2             COORDINATES : CARTESIAN         *
CC  POROSITY :  0.3                                                 *
CC  GRIDBLOCKS : 19 x 19 x 3 (1083)                                *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
Field2
CC
CC
*----HEADER
Karamay field (modified from ASP pilot, M. Delshad, 1998) PPG concentration
optimization
CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG
        1    2    3       1      1     0      0    0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX    NY    NZ  IDXYZ  IUNIT
     19    19    3    2       0
CC
CC  CONSTANT GRID BLOCK SIZE IN X
*----DX(I)
     19*32.8CC
CC  CONSTANT GRID BLOCK SIZE IN Y
*----DY
     19*32.8
CC
CC  VARIABLE GRID BLOCK SIZE IN Z
*----DZ
     10.  20.  10.
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
```

```
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
PPG
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
     1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*****************************************************************
CC                                                               *
CC    OUTPUT OPTIONS                                             *
CC                                                               *
CC*****************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN (0: DAYS, 1: PV)
*----ICUMTM  ISTOP
       0     0
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*****************************************************************
CC                                                               *
CC    RESERVOIR PROPERTIES                                       *
CC                                                               *
CC*****************************************************************
CC
CC
CC MAX. SIMULATION TIME (DAYS)
*---- TMAX
      1000
```

```
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      1740.45
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       0      2     3      3      0     0      0
CC
CC VARIABLE POROSITY
*----PORC1
     0.3
CC
CC VARIABLE X-PERMEABILITY (MILIDARCY)
*----PERMX(1)
 1648.1 1636.2 1634.9 1653.1 1659.0 1711.9 1817.3 1887.7 1941.6 1990.2
 2017.1 2024.7 2054.8 2116.8 2200.1 2286.3 2317.7 2311.8 2283.6
 1633.7 1614.1 1606.2 1623.7 1643.8 1704.1 1788.0 1913.3 1987.4 2024.0
 2024.9 2017.7 2040.8 2113.5 2227.4 2338.4 2377.4 2357.3 2310.2
 1629.7 1605.2 1593.0 1610.9 1664.9 1694.4 1776.4 1873.9 1990.9 2045.0
 2011.4 1957.0 2008.3 2078.4 2228.9 2360.0 2410.0 2376.4 2314.0
 1640.9 1618.3 1608.9 1628.4 1676.5 1682.3 1739.5 1816.9 1925.0 1988.3
 1961.2 1900.5 1878.7 1944.8 2132.4 2286.4 2357.1 2333.3 2278.2
 1666.8 1651.5 1648.4 1665.1 1656.9 1676.4 1688.0 1726.0 1786.6 1847.5
 1842.8 1801.1 1772.6 1799.9 1901.4 2100.1 2204.1 2224.4 2204.5
 1701.2 1692.2 1690.2 1653.6 1659.9 1667.0 1669.8 1666.4 1670.3 1677.8
 1713.9 1700.1 1686.2 1669.6 1732.7 1870.0 2041.6 2103.8 2133.3
 1702.8 1659.0 1646.0 1663.9 1654.4 1662.6 1673.0 1649.2 1585.6 1542.6
 1592.2 1665.5 1651.9 1622.0 1676.7 1803.3 1887.0 2040.2 2075.4
 1742.7 1738.9 1673.5 1644.4 1648.2 1644.6 1643.7 1589.7 1457.9 1413.8
 1448.7 1600.3 1651.2 1657.2 1708.2 1802.5 1903.4 2022.5 2052.0
 1782.7 1784.3 1723.8 1670.8 1620.7 1608.3 1566.3 1459.5 1310.4 1201.2
 1305.4 1482.7 1645.5 1711.4 1770.1 1866.9 1954.2 2040.4 2053.4
 1818.0 1824.9 1785.2 1717.3 1644.1 1559.9 1480.1 1415.1 1212.0 1085.0
 1211.3 1444.8 1600.3 1722.8 1851.2 1941.0 2017.0 2061.2 2061.8
 1831.8 1838.0 1810.0 1734.8 1653.0 1582.5 1507.2 1423.6 1280.7 1189.9
 1301.2 1500.1 1690.2 1823.3 1893.6 1960.0 2034.4 2067.0 2054.6
 1827.7 1826.8 1788.8 1722.1 1648.4 1590.0 1570.1 1519.4 1435.9 1390.1
 1495.4 1670.5 1857.0 1956.3 1987.4 1988.8 2019.7 2054.9 2045.3
 1818.5 1813.9 1787.9 1704.4 1640.3 1588.7 1577.0 1570.5 1556.5 1541.4
 1658.5 1835.1 2030.4 2129.9 2094.4 2021.0 2038.8 2030.0 2020.6
 1821.5 1816.5 1796.5 1714.2 1646.1 1586.2 1564.0 1581.7 1596.0 1620.6
 1733.5 1919.8 2119.4 2216.0 2147.2 2032.6 2017.0 1994.7 1985.1
 1842.2 1849.8 1839.6 1789.0 1680.4 1615.7 1597.4 1608.7 1626.7 1675.4
 1759.9 1920.8 2066.4 2132.5 2090.3 1987.0 1954.4 1938.0 1937.7
 1869.1 1896.4 1907.9 1855.6 1745.9 1656.3 1647.5 1641.9 1653.8 1691.0
 1749.8 1850.5 1942.3 1960.2 1920.5 1845.5 1825.2 1860.6 1882.2
 1883.6 1919.5 1943.0 1895.7 1767.8 1671.6 1649.0 1653.4 1666.6 1696.6
 1730.8 1791.1 1877.4 1864.6 1770.5 1718.2 1730.9 1771.5 1831.8
 1877.9 1904.1 1914.9 1872.4 1772.7 1689.5 1667.2 1676.9 1704.9 1744.1
 1772.1 1807.1 1807.5 1763.6 1707.2 1672.0 1699.5 1752.3 1801.4
 1859.5 1871.3 1867.8 1833.0 1771.1 1715.2 1702.6 1704.9 1721.3 1748.1
 1757.9 1778.9 1775.3 1744.9 1717.9 1694.9 1711.4 1749.6 1790.2
 2024.1 2034.6 2034.8 2014.7 1960.2 1898.9 1814.4 1767.9 1740.6 1750.5
 1739.7 1763.2 1806.6 1870.5 1944.6 2017.3 2043.8 2041.4 2023.1
 2038.6 2057.3 2065.2 2044.8 1980.1 1901.5 1829.8 1755.4 1728.1 1727.0
 1726.6 1748.3 1794.3 1870.2 1968.2 2058.6 2088.9 2075.3 2043.3
 2043.1 2066.7 2080.0 2057.8 1989.4 1892.0 1819.9 1755.0 1725.5 1717.0
 1723.7 1743.9 1774.0 1847.8 1973.8 2075.8 2113.0 2089.4 2047.4
 2033.4 2052.4 2060.5 2031.5 1956.8 1861.7 1805.6 1755.7 1731.7 1728.3
```

1725.8	1733.2	1748.0	1796.7	1905.7	2023.0	2075.6	2060.4	2025.5	
2013.7	2018.8	2010.5	1970.2	1895.2	1827.2	1767.3	1753.4	1741.5	1745.1
1725.0	1709.9	1688.9	1709.2	1778.5	1891.1	1970.1	1989.3	1981.6	
1997.1	1987.9	1963.5	1911.3	1841.3	1775.5	1743.9	1742.7	1747.1	1719.8
1721.4	1678.4	1629.4	1594.7	1649.1	1767.0	1863.5	1917.4	1954.5	
2002.1	1992.5	1960.1	1890.3	1819.2	1752.8	1723.0	1743.8	1759.3	1742.4
1732.6	1695.0	1597.0	1538.0	1600.2	1725.9	1828.1	1901.9	1936.8	
2018.3	2005.3	1965.4	1911.0	1835.4	1777.5	1749.1	1767.9	1779.9	1799.1
1772.5	1733.0	1646.9	1600.8	1650.4	1759.8	1860.1	1922.4	1951.5	
2049.0	2045.8	2008.4	1949.6	1883.0	1826.9	1799.2	1804.7	1844.6	1861.1
1839.8	1784.1	1739.8	1718.4	1758.7	1845.0	1929.3	1978.7	1989.0	
2086.9	2091.7	2065.8	2008.8	1959.7	1883.0	1865.5	1853.8	1875.7	1891.0
1869.1	1828.5	1803.4	1803.4	1855.8	1925.9	1999.9	2034.1	2025.9	
2097.1	2105.0	2087.5	2035.8	1977.0	1933.2	1909.3	1872.3	1878.8	1880.4
1877.3	1854.8	1852.5	1908.6	1936.0	1984.1	2035.9	2055.0	2046.8	
2094.4	2098.3	2079.3	2035.5	1978.4	1928.8	1904.9	1904.4	1880.0	1875.4
1884.5	1917.9	1929.5	1943.5	1966.3	1997.4	2031.3	2047.9	2046.3	
2121.0	2115.3	2083.6	2035.3	1970.3	1896.7	1859.9	1882.4	1915.2	1885.2
1930.5	1953.2	1958.4	1956.2	1972.6	2003.4	2037.2	2048.9	2052.7	
2151.7	2150.2	2135.6	2079.0	1984.1	1879.0	1816.0	1868.4	1920.8	1966.8
1986.1	1972.1	1963.3	1951.0	1973.3	2022.8	2066.1	2078.6	2080.5	
2195.6	2209.4	2204.0	2155.0	2059.5	1968.2	1913.3	1946.4	1977.4	2019.2
2013.1	2015.5	1998.6	1987.5	2032.2	2111.1	2138.4	2142.0	2131.3	
2236.5	2269.4	2283.9	2237.8	2152.0	2114.5	2126.7	2092.0	2069.4	2061.3
2047.4	2056.5	2067.1	2097.7	2182.7	2256.3	2270.4	2231.3	2196.0	
2257.2	2295.8	2319.0	2280.2	2197.7	2179.7	2202.0	2163.6	2119.6	2098.0
2082.9	2105.9	2169.3	2259.8	2357.4	2410.2	2381.5	2325.4	2255.7	
2254.7	2282.8	2294.8	2264.6	2207.2	2183.5	2183.4	2164.6	2149.0	2138.7
2132.0	2167.6	2230.4	2323.1	2419.8	2457.0	2428.2	2372.7	2320.7	
2239.4	2254.4	2256.0	2235.1	2202.0	2180.5	2165.3	2150.4	2156.1	2154.6
2152.9	2192.7	2254.9	2333.2	2406.3	2432.2	2414.6	2373.7	2330.2	
1557.9	1580.9	1584.6	1555.3	1489.2	1405.4	1296.3	1239.5	1209.1	1183.9
1140.6	1109.6	1071.3	1037.7	1015.4	1013.6	1009.2	1010.8	1016.6	
1582.4	1620.1	1635.5	1603.3	1516.7	1407.6	1314.5	1225.6	1199.6	1189.7
1164.2	1121.1	1069.5	1028.7	1006.3	1003.9	1000.3	1003.3	1011.4	
1588.0	1636.3	1661.0	1624.1	1517.6	1390.3	1296.1	1217.3	1196.6	1195.0
1176.5	1126.3	1055.4	1013.0	1005.9	999.4	997.0	1000.4	1010.2	
1563.3	1607.2	1625.6	1578.6	1462.8	1339.9	1265.1	1205.6	1192.2	1185.4
1154.5	1098.6	1037.9	993.3	989.9	996.3	998.9	1003.7	1015.3	
1509.3	1533.0	1529.2	1470.1	1355.8	1260.4	1193.1	1180.9	1177.3	1160.4
1109.2	1048.4	980.9	963.2	966.6	979.7	999.3	1013.1	1029.2	
1442.9	1445.2	1423.1	1355.2	1265.5	1182.3	1142.3	1149.0	1160.6	1123.0
1076.5	1000.2	925.4	881.6	908.7	969.2	1000.3	1032.0	1043.3	
1356.6	1380.4	1355.5	1295.0	1205.8	1143.4	1116.0	1133.0	1147.8	1131.3
1079.7	1002.5	890.9	834.0	880.7	967.1	1028.2	1059.2	1087.6	
1313.4	1303.5	1282.3	1247.0	1198.7	1156.5	1133.7	1147.7	1152.9	1156.1
1116.5	1044.7	941.0	890.4	926.1	1003.3	1086.3	1130.7	1154.1	
1296.4	1290.6	1273.9	1242.1	1203.6	1176.3	1157.4	1160.4	1203.6	1232.2
1194.4	1108.7	1032.8	997.5	1013.5	1092.8	1180.7	1229.4	1234.0	
1298.0	1299.8	1285.1	1248.5	1208.2	1147.7	1152.7	1168.2	1234.3	1278.0
1232.7	1148.6	1082.0	1069.3	1096.2	1177.2	1273.9	1319.5	1301.8	
1295.7	1308.0	1285.9	1227.3	1167.7	1131.0	1127.3	1135.5	1197.5	1232.1
1202.7	1139.7	1096.0	1114.1	1147.1	1225.7	1318.3	1355.0	1333.5	
1284.2	1290.0	1264.8	1203.6	1131.1	1071.1	1048.2	1079.9	1117.5	1144.5
1143.0	1121.3	1087.7	1083.4	1125.1	1201.5	1288.2	1327.5	1316.0	
1265.0	1259.5	1224.5	1169.9	1085.8	990.2	941.5	987.6	1065.1	1078.4
1110.1	1090.2	1056.9	1037.3	1073.4	1151.0	1226.3	1270.5	1277.3	
1250.5	1241.4	1215.0	1164.3	1073.2	950.4	874.0	943.9	1026.4	1075.7
1092.0	1076.4	1037.1	1010.0	1046.2	1125.5	1188.4	1229.4	1245.4	
1255.0	1255.8	1243.2	1196.9	1120.2	1029.1	973.6	1012.4	1053.4	1096.7

```
 1094.2 1096.6 1065.7 1048.1 1089.9 1166.2 1198.9 1224.5 1235.4
 1269.8 1286.2 1293.0 1256.7 1186.0 1160.4 1169.1 1139.8 1124.0 1122.5
 1111.5 1110.2 1121.3 1135.6 1193.4 1245.3 1265.6 1249.6 1245.1
 1278.9 1301.8 1317.0 1288.2 1224.3 1211.8 1232.0 1201.1 1164.8 1148.2
 1133.4 1142.6 1157.0 1233.4 1290.8 1321.7 1313.8 1296.1 1262.5
 1275.7 1292.6 1299.9 1276.9 1232.9 1215.1 1213.7 1196.2 1173.9 1157.2
 1140.8 1159.5 1198.3 1258.2 1326.4 1346.0 1332.6 1309.7 1291.8
 1264.6 1272.8 1272.3 1255.6 1229.7 1212.8 1195.0 1182.0 1176.9 1168.3
 1155.5 1177.1 1215.3 1265.3 1320.5 1333.9 1326.4 1309.8 1294.3
CC
CC VARIABLE Y-PERMEABILITY (MILIDARCY) FOR LAYER K = 1,NZ
*----FACTY
     1.0
CC
CC VARIABLE Z-PERMEABILITY
*----FACTZ
     0.1
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        2       2
CC
CC VARIABLE DEPTH (FT)
*----D111
     4150
CC
CC VARIABLE PRESSURE (PSIA) BLOCK I = 1,NX*NY*NZ
*----P(I,1) I=1,NX*NY*NZ
  1773.4  1772.1  1771.0  1770.4  1770.2  1770.0  1769.8  1769.4  1769.1
1768.9
  1769.5  1770.2  1770.8  1771.2  1771.1  1770.8  1770.6  1770.8  1771.0
  1772.5  1771.0  1769.6  1769.6  1769.7  1769.7  1769.6  1769.2  1768.5
1767.8
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1777.9
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1775.0
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1777.9
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1780.2
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1781.9
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1781.8
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1781.8
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  1785.0  1783.8  1783.1  1782.5  1782.3  1782.3  1782.1  1782.0  1782.0
1782.2
  1782.4  1782.4  1782.4  1781.8  1780.9  1780.3  1780.7  1781.3  1781.5
CC
CC VARIABLE INITIAL WATER SATURATION BLOCK I = 1,NX*NY*NZ (FRACTION)
*----S(I,1) I=1,NX*NY*NZ
  0.3295  0.3271  0.3272  0.3318  0.3403  0.3492  0.3570  0.3625  0.3675
0.3746
  0.3838  0.3968  0.4117  0.4242  0.4097  0.3926  0.3798  0.3712  0.3649
  0.3316  0.3280  0.3242  0.3321  0.3442  0.3560  0.3649  0.3690  0.3704
0.3743
  0.3838  0.3950  0.4038  0.4083  0.4013  0.3895  0.3781  0.3719  0.3701
  0.3343  0.3272  0.4804  0.4974  0.5068  0.5125  0.5158  0.5150  0.5138
0.5110
  0.5160  0.5194  0.5302  0.5347  0.5218  0.5171  0.5124  0.5124  0.3757
  0.3386  0.3333  0.4957  0.5048  0.5117  0.5167  0.5202  0.5194  0.5195
0.5194
  0.5229  0.5340  0.5436  0.5485  0.5360  0.5196  0.5173  0.5160  0.3882
  0.3433  0.3413  0.5041  0.5106  0.5167  0.5221  0.5633  0.5748  0.5622
0.5544
  0.5604  0.5771  0.5923  0.5936  0.5725  0.5396  0.5199  0.5193  0.4066
  0.3474  0.3482  0.5094  0.5149  0.5213  0.5946  0.6112  0.6089  0.6041
0.6013
  0.6017  0.6051  0.6104  0.6126  0.5986  0.5682  0.5370  0.5366  0.4221
  0.3501  0.3524  0.5123  0.5176  0.5463  0.6089  0.6858  0.5088  0.4601
0.4508
  0.4514  0.4602  0.4949  0.7536  0.7075  0.6873  0.6392  0.6348  0.4117
  0.3501  0.6095  0.6166  0.6239  0.6426  0.7064  0.7285  0.4884  0.4681
0.4559
  0.4563  0.4659  0.4816  0.7218  0.7013  0.6682  0.6317  0.6263  0.4026
  0.3501  0.6097  0.6171  0.6239  0.6310  0.6990  0.7169  0.4715  0.4657
0.4577
  0.4573  0.4613  0.4653  0.7111  0.6941  0.6466  0.6221  0.6170  0.3943
  0.3491  0.6078  0.6168  0.6238  0.6301  0.6805  0.7116  0.4602  0.4607
0.4577
  0.4568  0.4570  0.4567  0.7055  0.6832  0.6328  0.6170  0.6151  0.3858
  0.3484  0.6043  0.6167  0.6243  0.6306  0.6857  0.7123  0.4574  0.4587
0.4570
  0.4569  0.4573  0.4566  0.7066  0.6889  0.6340  0.6165  0.6120  0.3799
  0.3510  0.6090  0.6182  0.6255  0.6421  0.7029  0.7187  0.4660  0.4617
0.4572
  0.4578  0.4628  0.4676  0.7139  0.6971  0.6536  0.6181  0.6147  0.3813
  0.3530  0.6116  0.6191  0.6268  0.6739  0.7110  0.7307  0.4833  0.4659
0.4570
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  0.4577  0.4674  0.4885  0.7302  0.7061  0.6868  0.6277  0.6157  0.3841
  0.3533  0.6114  0.6185  0.6267  0.6860  0.7173  0.7881  0.6328  0.6176
0.6125
  0.6136  0.4584  0.5193  0.6971  0.7189  0.6858  0.6412  0.3949  0.3843
  0.3528  0.3544  0.6120  0.6193  0.6496  0.6993  0.6159  0.6107  0.6027
0.5986
  0.6011  0.4443  0.4567  0.4761  0.7074  0.6785  0.6352  0.3906  0.3815
  0.3493  0.3492  0.6059  0.6144  0.6222  0.6679  0.5950  0.5939  0.5745
0.5554
  0.5736  0.4305  0.4393  0.4405  0.6863  0.6404  0.6309  0.3818  0.3756
  0.3449  0.3419  0.5952  0.6080  0.6166  0.6226  0.5373  0.5371  0.5229
0.5302
  0.5487  0.4211  0.4261  0.4232  0.6434  0.6302  0.6245  0.3727  0.3681
  0.3422  0.3425  0.3440  0.3568  0.3694  0.3804  0.3884  0.3913  0.3937
0.3986
  0.4062  0.4164  0.4213  0.4115  0.6265  0.6195  0.6170  0.3642  0.3601
  0.3399  0.3412  0.3457  0.3554  0.3655  0.3744  0.3809  0.3850  0.3901
0.3970
  0.4069  0.4196  0.4299  0.4156  0.3916  0.3753  0.3646  0.3592  0.3522
  0.3299  0.3280  0.3281  0.3336  0.3426  0.3515  0.3593  0.3650  0.3700
0.3770
  0.3864  0.3990  0.4117  0.4214  0.4091  0.3946  0.3823  0.3743  0.3690
  0.3314  0.3284  0.3247  0.3328  0.3451  0.3570  0.3663  0.3707  0.3724
0.3765
  0.3861  0.3972  0.4053  0.4090  0.4025  0.3916  0.3804  0.3746  0.3732
  0.3339  0.3271  0.4808  0.4972  0.5067  0.5127  0.5161  0.5154  0.5145
0.5120
  0.5167  0.5206  0.5348  0.5384  0.5258  0.5177  0.5136  0.5135  0.3782
  0.3388  0.3336  0.4956  0.5046  0.5116  0.5167  0.5203  0.5196  0.5201
0.5202
  0.5262  0.5373  0.5458  0.5497  0.5377  0.5202  0.5179  0.5167  0.3901
  0.3440  0.3421  0.5041  0.5105  0.5165  0.5219  0.5600  0.5759  0.5660
0.5589
  0.5648  0.5798  0.5921  0.5931  0.5717  0.5408  0.5240  0.5207  0.4060
  0.3485  0.3493  0.5095  0.5149  0.5210  0.5932  0.6099  0.6085  0.6044
0.6019
  0.6022  0.6053  0.6104  0.6129  0.5982  0.5679  0.5394  0.5410  0.4185
  0.3515  0.3537  0.5125  0.5176  0.5423  0.6075  0.6745  0.5059  0.4701
0.4601
  0.4609  0.4711  0.5043  0.7724  0.7074  0.6868  0.6419  0.6397  0.4113
  0.3516  0.6106  0.6171  0.6241  0.6416  0.7059  0.7276  0.4861  0.4752
0.4683
  0.4686  0.4744  0.4837  0.7226  0.7008  0.6684  0.6350  0.6318  0.4040
  0.3515  0.6109  0.6176  0.6242  0.6317  0.6997  0.7171  0.4769  0.4744
0.4708
  0.4704  0.4724  0.4744  0.7111  0.6938  0.6487  0.6262  0.6193  0.3969
  0.3505  0.6091  0.6173  0.6242  0.6304  0.6848  0.7124  0.4719  0.4724
0.4712
  0.4704  0.4703  0.4690  0.7059  0.6871  0.6369  0.6184  0.6158  0.3893
  0.3496  0.6058  0.6172  0.6246  0.6310  0.6902  0.7131  0.4705  0.4718
0.4709
  0.4705  0.4704  0.4688  0.7070  0.6904  0.6385  0.6170  0.6133  0.3833
  0.3524  0.6102  0.6186  0.6258  0.6455  0.7031  0.7189  0.4744  0.4730
0.4708
  0.4709  0.4726  0.4740  0.7134  0.6968  0.6555  0.6208  0.6154  0.3843
  0.3547  0.6126  0.6197  0.6271  0.6744  0.7106  0.7299  0.4830  0.4747
0.4700
  0.4700  0.4737  0.4831  0.7268  0.7048  0.6855  0.6310  0.6163  0.3875
  0.3550  0.6124  0.6192  0.6271  0.6856  0.7164  0.7798  0.6309  0.6174
0.6128
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  0.6140  0.4671  0.5024  0.6193  0.7159  0.6840  0.6429  0.3964  0.3877
  0.3545  0.3564  0.6129  0.6201  0.6529  0.6989  0.6145  0.6095  0.6023
0.5989
  0.6015  0.4435  0.4544  0.4646  0.7035  0.6772  0.6354  0.3920  0.3840
  0.3510  0.3512  0.6072  0.6154  0.6229  0.6720  0.5946  0.5933  0.5765
0.5610
  0.5809  0.4304  0.4382  0.4377  0.6836  0.6390  0.6312  0.3830  0.3784
  0.3465  0.3439  0.5973  0.6093  0.6177  0.6233  0.5409  0.5394  0.5258
0.5355
  0.5548  0.4216  0.4261  0.4221  0.6399  0.6302  0.6250  0.3745  0.3713
  0.3437  0.3443  0.3464  0.3593  0.3720  0.3825  0.3908  0.3936  0.3961
0.4008
  0.4081  0.4176  0.4211  0.4107  0.6268  0.6201  0.6179  0.3666  0.3642
  0.3414  0.3431  0.3481  0.3582  0.3685  0.3774  0.3838  0.3889  0.3939
0.4004
  0.4091  0.4192  0.4257  0.4135  0.3923  0.3772  0.3675  0.3631  0.3583
  0.3302  0.3283  0.3286  0.3338  0.3422  0.3510  0.3589  0.3647  0.3699
0.3769
  0.3867  0.4011  0.4171  0.4303  0.4158  0.3979  0.3831  0.3739  0.3665
  0.3323  0.3290  0.3251  0.3332  0.3453  0.3570  0.3664  0.3711  0.3732
0.3773
  0.3871  0.3991  0.4084  0.4136  0.4065  0.3950  0.3826  0.3760  0.3730
  0.3351  0.3279  0.4802  0.4968  0.5064  0.5126  0.5162  0.5155  0.5145
0.5121
  0.5167  0.5201  0.5331  0.5372  0.5279  0.5183  0.5144  0.5141  0.3797
  0.3400  0.3345  0.4953  0.5044  0.5113  0.5165  0.5200  0.5193  0.5195
0.5194
  0.5221  0.5316  0.5382  0.5422  0.5334  0.5217  0.5184  0.5173  0.3944
  0.3450  0.3430  0.5039  0.5103  0.5161  0.5212  0.5465  0.5591  0.5516
0.5459
  0.5510  0.5619  0.5765  0.5854  0.5574  0.5362  0.5247  0.5263  0.4138
  0.3495  0.3503  0.5094  0.5146  0.5203  0.5722  0.6068  0.6064  0.6027
0.6001
  0.6005  0.6037  0.6086  0.6109  0.5968  0.5563  0.5367  0.5442  0.4297
  0.3524  0.3542  0.5126  0.5174  0.5309  0.6045  0.6535  0.4908  0.4619
0.4561
  0.4567  0.4636  0.4994  0.7611  0.7061  0.6701  0.6375  0.6386  0.4184
  0.3527  0.6106  0.6172  0.6239  0.6329  0.7039  0.7257  0.4794  0.4661
0.4620
  0.4622  0.4661  0.4766  0.7216  0.6989  0.6548  0.6322  0.6310  0.4077
  0.3526  0.6108  0.6176  0.6240  0.6305  0.6875  0.7157  0.4675  0.4661
0.4641
  0.4638  0.4650  0.4664  0.7097  0.6865  0.6394  0.6254  0.6213  0.3988
  0.3514  0.6091  0.6172  0.6238  0.6298  0.6710  0.7112  0.4647  0.4652
0.4647
  0.4641  0.4639  0.4630  0.7049  0.6652  0.6322  0.6197  0.6163  0.3905
  0.3506  0.6059  0.6170  0.6241  0.6303  0.6761  0.7119  0.4637  0.4648
0.4644
  0.4640  0.4638  0.4627  0.7057  0.6702  0.6326  0.6175  0.6142  0.3841
  0.3533  0.6101  0.6185  0.6253  0.6342  0.7008  0.7181  0.4661  0.4655
0.4642
  0.4640  0.4649  0.4658  0.7120  0.6934  0.6427  0.6202  0.6159  0.3846
  0.3558  0.6126  0.6197  0.6268  0.6644  0.7094  0.7296  0.4768  0.4667
0.4635
  0.4633  0.4654  0.4762  0.7254  0.7026  0.6627  0.6277  0.6165  0.3871
  0.3564  0.6125  0.6196  0.6271  0.6787  0.7159  0.7866  0.6319  0.6178
0.6123
  0.6135  0.4604  0.5001  0.6263  0.7137  0.6797  0.6400  0.3967  0.3868
  0.3559  0.3581  0.6135  0.6204  0.6487  0.6988  0.6150  0.6101  0.6021
0.5974
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  0.5998  0.4437  0.4542  0.4628  0.6995  0.6639  0.6352  0.3922  0.3832
  0.3525  0.3533  0.6080  0.6161  0.6231  0.6632  0.5949  0.5933  0.5683
0.5518
  0.5650  0.4311  0.4383  0.4368  0.6801  0.6366  0.6314  0.3832  0.3774
  0.3478  0.3459  0.5982  0.6101  0.6182  0.6236  0.5436  0.5401  0.5270
0.5338
  0.5497  0.4229  0.4271  0.4225  0.6373  0.6306  0.6257  0.3750  0.3702
  0.3444  0.3454  0.3479  0.3606  0.3730  0.3834  0.3919  0.3945  0.3973
0.4024
  0.4103  0.4207  0.4241  0.4136  0.6275  0.6212  0.6187  0.3670  0.3624
  0.3412  0.3430  0.3481  0.3580  0.3681  0.3769  0.3833  0.3882  0.3934
0.4008
  0.4116  0.4241  0.4350  0.4193  0.3951  0.3783  0.3680  0.3622  0.3543CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.0583    0.0025
CC
CC*****************************************************************
CC                                                                *
CC    PHYSICAL PROPERTY DATA                                      *
CC                                                                *
CC*****************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
```

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CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     0      0    0
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC  S2RWC  S3RWC
     .25    .15    .20
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW     P3RW
     .20     0.95     0.20
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W     E2W      E3W
     3.0     2.0      2.0
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     0.46    40    0
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0 CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
```

```
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
```

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* -- IRKPPG,RKCUTPPG,     DPPG,      APPGS,   PPGNS,  DCRICWS  TOLPPGIN
      2    1000000000    0.0003281     12     -0.3     0.05      100
CC
CC
* -- APPGFR, PPGNFR
       20     -0.2
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
       2       0.001     0.2    1e-6
CC
CC
* ---- APPG1,  APPG2, GAMCPG, GAMHFPG,POWNPG
       1e-6    1e-6   0.0     0.0     1.8
CC
CC*******************************************************************
CC                                                                  *
CC    WELL DATA                                                     *
CC                                                                  *
CC*******************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      13      2      1      13
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    17     3      4       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A1
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2    10   3    4       .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A2
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      3700.   0.0     7100.
CCCC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      3    14     7      1       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A3
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
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CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     4    18   11    4       .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A4
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      3700.   0.0     7100.
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      5    3     3      4       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A5
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     6    7   7    1       .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A6
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
     0     0.0      3700.   0.0     7100.
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      7    10     10      4       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A7
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     8    14   14    1      .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A8
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      3700.   0.0     7100.
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CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      9    16    18      2       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A9
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     10    2   11    4       .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A10
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      3700.   0.0     7100.
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      11    7     14      1       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A11
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     12    9   17    4       .49       0.     3     1         3       0
CC
CC WELL NAME
*---- WELNAM
A12
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      3700.   0.0     7100.
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      13    3     17      4       .49     0.      3      1        3    0
CC
CC WELL NAME
*---- WELNAM
A13
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       3700    0.0     7100.
```

```
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     1   -679.19
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     2   -803.88
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 3     2035. 1. 0. 0. 0.     0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 3     0.    0. 0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 3     0.    0. 0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     4  -928.32
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     5   -850.24
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 6     2197.99  1.  0. 0. 0.     0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 6     0.       0.  0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 6     0.       0.  0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     7   -2088.94
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 8     2323.00  1.  0. 0. 0.     0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 8     0.       0.  0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 8     0.       0.  0. 0. 0.     0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   PWF
     9  1740.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     10   -843.90
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 11    2010.11   1.  0. 0. 0.     0.0583 0.   0.  0. 0.  0.   0. 0. 0. 0.
 11    0.        0.  0. 0. 0.     0.     0.   0.  0. 0.  0.   0. 0. 0. 0.
 11    0.        0.  0. 0. 0.     0.     0.   0.  0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     12    -611.97
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     13   -693.95
```

```
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR ERITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1   WRHPV   WRPRF      RSTC
     100.    26.0     26.0      1.0     5      30.0
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NUMBER
*----DT      DCLIM   CNMAX   CNMIN
     0.01    0.01    0.1       0.01
cc
CC IRO, ITSTEP, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITSTEP IFLAG(M),M=1,NWELL
       2   1    4  4  1  4  4  1  4  1  2  4  1  4  4
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
      0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     12     1  2  3  4  5  6  7  8  10  11  12  13
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     1   -625.91
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     2   -942.54
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 3     1994.57 1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 2000.
 3     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 3     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     4   -1059.46
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     5   -829.07
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 6     2173.97 1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 2000.
 6     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 6     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     7   -2465.65
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 8     2250.25  1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 2000.
 8     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 8     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
```

```
*----ID   QT
     10  -692.0
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 11    1956.79  1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 2000.
 11    0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 11    0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     12  -220.73
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     13  -795.53
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR ERITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1    WRHPV   WRPRF      RSTC
     400.0    50.0     50.0       5.0    25.0       50
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURNAT NO.
*----DT      DCLIM   CNMAX   CNMIN
     0.01    0.001    0.1       0.00001
cc
CC IRO, ITSTEP, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITSTEP IFLAG(M),M=1,NWELL
       2   1    4  4  1  4  4  1  4  1  2  4  1  4  4
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
      0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     12     1  2  3  4  5  6  7  8  10  11  12  13
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     1   -619.07
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     2   -746.2
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 3     2000.93 1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 3     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 3     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     4   -1071.65
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     5   -884.73
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
```

```
*----ID  QI(M,L)  C(M,KC,L)
 6     2097.34 1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 6     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 6     0.      0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     7   -2041.19
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 8     2250.96  1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 8     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 8     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     10  -1521.71
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
 11     2076.15  1.0     0. 0. 0.   0.0583   0.  0. 0. 0.  0.   0. 0. 0. 0.
 11     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
 11     0.       0.      0. 0. 0.   0.       0.  0. 0. 0.  0.   0. 0. 0. 0.
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     12  -213.65
CC
CC ID, PRODUCING RATE FOR RATE CONSTRAINT WELL (IFLAG=4)
*----ID   QT
     13  -696.41
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR ERITING TO OUTPUT FILES
*----TINJ    CUMPR1      CUMHI1     WRHPV      WRPRF      RSTC
     1000.0    100.0     100.0      5.0        100.0     200.0
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURNAT NOS.
*----DT       DCLIM   CNMAX   CNMIN
     0.005    0.0008    0.1    0.00001
```

C-3. Input data for field case III, PPG size selection (PPG 3, 170 Mesh)

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) : 1992             PROCESS :  PROFILE CONTROL       *
CC  THICKNESS (FT) : 85.5             INJ. PRESSURE (PSI) :  -      *
CC  WIDTH (FT) :  2542             COORDINATES : CARTESIAN          *
CC  POROSITY :  variable                                            *
CC  GRIDBLOCKS : 24 x 31 x 47 (34968)                              *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
Field3
CC
CC
*----HEADER
Chevron field, sector model with some modifications
Field case optimization - PPG diameter

CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT ICOORD ITREAC ITC IENG
      1     2    3      0      1      0      0   0
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     24    31    47    0     0
CC
CC CONSTANT CARTESIAN GRID
*----DX1   DY1   DZ1
     83    82    1.82
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW   NG
     14  0     6
CC
CC  All species must be present even for standard waterflood.
*--- species name
WATER
OIL
none
```

```
none
SALT
none
none
none
none
none
none
none
none
PPG
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
      1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*********************************************************************
CC                                                                    *
CC    OUTPUT OPTIONS                                                  *
CC                                                                    *
CC*********************************************************************
CC
CC ICUMTM=0==>TIME PRINTING;istop=1==>PV SPEC
CC FLAGS FOR PV OR DAYS
*----ICUMTM  ISTOP
     0       0
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
      1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL IPTEMP
     1      1     1      1     0
CC  ICKL is phase conc.  (K is component and L is phase)
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----ICKL IVIS IPER ICNM ICSE
     0    1    0    0   0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO UNIT 6 (PROFIL)
*----IADS  IVEL IRKF IPHSE
     0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME
*---- TMAX
      1500
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR      PSTAND
     0.000008   14.7
CC  Porosity Values For Each Grid Input Given Through Include Files
CC  FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRANZ  INTG
```

```
     4     4      3      3      0     0       0
CC
CC Constant permeability multiplier for Y direction permeability
*----FACTY
     1
CC
CC Constant permeability multiplier for Z direction permeability
*----FACTZ
     0.1
CC Depth To The Top Layer Input Given Through Include Files
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
     4       1       4
CC
CC
*----PINIT    HINIT
     2915     6843
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.0513   0.0
CC
CC*******************************************************************
CC                                                                  *
CC PHYSICAL PROPERTY DATA                                           *
CC                                                                  *
CC*******************************************************************
CC
CC DW
CC OIL CONC. AT PLAIT POINT FOR TYPE II(+) AND TYPE II(-), CMC (do not change)
*---- EPSME
      0.0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.0    0.055  0      0.035  0.     0.055
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1(7) AND ALCOHOL 2 (8)
*----CSEL7     CSEU7     CSEL8  CSEU8
     0.5       0.85      0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0     0     0.0
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.0      0      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1  (leave as is)
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671    1.79   48   35.31  0.222
```

```
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC  0 = Healy and Reed and 1 is Chun-Huh
*--- ift
     1
CC
CC INTERFACIAL TENSION PARAMETERS
*----CHUH  AHUH
     0.3   10.
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.48
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     2       2000.      75000.     365.
CC
CC
*----iperm     IRTYPE
     0          0
CC RESIDUAL SATURATION FOR EACH PHASE INPUT GIVEN THROUGH INCLUDE FILES
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     0      0    0
CC
CC
*----S1RWC  S2RWC  S3RWC
     0.08    0.33    0.14
CC
CC CONSTANT ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW  P2RW  P3RW
     0.45   0.75  0.30
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W   E2W  E3W
     3     2    3
CC
CC  RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----S1RC(=SWIR)  S2RC(=SORCHEM)  S3RC(SMER=SWIR)
     0.0001    0.0001   0.0001
CC
CC ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----P1RC P2RC P3RC
     1.    1.    1.
CC
CC REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----E13CW  E23C E31C
     1      1    1
CC
CC WATER AND OIL VISCOSITY at reference temperature, RESERVOIR TEMPERATURE
(leave zero)
*----VIS1   VIS2  TEMPV
     0.5   2.5    180
CC
CC MICROEMULSION VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
```

```
       .1      2.5      0.1        0.1      0.1
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1       AP2      AP3
    45         625      1000
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SSLOPE
     1.     .01   -0.377
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY (50% shear ~ 10 cP)
*----GAMMAC  GAMHF  POWN   IPMOD  ISHEAR   RWEFF  GAMHF2  IWREATH
      4       30    1.8     0       1       0.4   0.0    1
CC
CC WREATH CORRELATION PARAMETERS
*----WREATHM  WREATHB  WREATHN  WREATHT
     4.7      0.18     0.48     1.0
CC
CC FLAG FOR POLYMER (4) PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4   BRK    CRK    rkcut
     1      1.    1       100   0.04      10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2  DEN3 DEN7 DEN8 IDEN
     .433  .377  .433 .346  0.  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      1
CC
CC  FVF FOR PHASE 1,2,3
*-----(FVF(L),L=1,NPHAS)
      1    1.083    1
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.000003   0.00001        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0     0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
     0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9) D(10) D(1
     0.   0.   0.   0.    0.  0.  8*0.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9)  D(10)  D(11)
     0.   0.   0.   0.   0.   0.  8*0.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6) D(7) D(8) D(9) D(10)  D(11)
```

```
     0.   0.   0.   0.   0.   0.   8*0.
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY (ft) OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     4             0.4
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     4             0.4
CC Mojdeh
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     4            0.4
CC   Polymer (7 microg/g), surf. (0.3 mg/g)
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31  AD32  B3D    AD41   AD42  B4D      iadk   iads1   fads refk(mD)
     0.125     0.0  1000.  1   0.    100.       0       0     0   0.
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT MW (needed for cation
exch)
*----QV      XKC   XKS  EQW
     0.0     0.0   0.0  429.
CC
CC
*---  KGOPT
     4

CC
CC
* -- IRKPPG,RKCUTPPG,     DPPG,        APPGS,   PPGNS,   DCRICWS    OLPPGIN

      2     1000000000    0.0002067    30      -0.3     0.05       50
CC
CC
* -- APPGFR, PPGNFR
       40      -0.3
CC
CC
*---  ADPPGA,  ADPPGB  RESRKFAC,TOLPPGRK
      0        0       0.2      1e-6
CC
CC
* ---- APPG1,   APPG2,  GAMCPG, GAMHFPG, POWNPG
       1e-6     1e-6    0.0     0.0      1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELLRADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      3      2      1      3
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1    24     14      1       0.4     0.      3      1       47    1
CC
```

```
CC
*----kprf
      0 1 1 0 0 1 1 1 1 0 0 0 0 0 0 1 1 0 0 0 1 1 1 1 1 1 1 1 1 1 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0
CC
CC WELL NAME
*---- WELNAM
INJ
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     2   2   27    2       0.4       0.     3     1         47       1
CC
CC
*----kprf
      0 0 0 0 1 1 1 1 1 1 0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 0 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0
CC
CC WELL NAME
*---- WELNAM
PROD_1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
     3   2   8   2       0.4       0.     3     1         47       1
CC
CC
*----kprf
     0 0 0 0 1 1 1 1 1 1 1 1 0 0 0 0 0 0 0 1 1 1 1 0 0 0 0 1 1 1 1 1 1 1 1
00 0 0 0 0 0 0 0 0 0
CC
CC WELL NAME
*---- WELNAM
PROD_2
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)

*----ID  QI(M,L)  C(M,KC,L)
     1    6738       1.   0.  0.     0.   0.05         0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
    2    600
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
```

```
*----ID   PWF
     3    1200
C
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
    500        20       20            20           20          50
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM      CNMAX   CNMIN
    0.000001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,C,L)

     1    6738        1     0.   0.     0.   0.05        0.    0.    0.    0.
0.   0.   0.   0.   2000
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
C
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     800      5       5            5           5          10
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.000001   0.01          0.1   0.01 CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2  2
CC
CC NUMBE OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COM. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    6738       1.     0.   0.     0.   0.05        0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.         0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
```

```
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
    1500      20       20             20            20          50
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.000001   0.01           0.1   0.01
```

Appendix D. Input Data for Synthetic Fracture Model

D-1. Input data for the slanted fracture plane model

```
CC*******************************************************************
CC                                                                  *
CC    BRIEF DESCRIPTION OF DATA SET                                 *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC                                                                  *
CC                                                                  *
CC  LENGTH (FT) :  100             PROCESS :  PROFILE CONTROL       *
CC  THICKNESS (FT) : 30            INJ. PRESSURE (PSI) :   -        *
CC  WIDTH (FT) :   100             COORDINATES : CARTESIAN          *
CC  POROSITY :    0.25                                              *
CC  GRIDBLOCKS :   50 x 50 x 15                                    *
CC  DATE :                                                          *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
SlantPlane
CC
CC
*----HEADER
EDFM synthetic model, Slant fracture plane, PPG treatment


CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG  IFRAC
        1    2    0      1      1     0      0    0      1
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     50   50   15   0       0
CC
CC NUMBER OF FRACTURE GRIDBLOCKS
*----NF  MAXF
     884   50
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX         DY           DZ
     2          2            2
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
```

```
*---- SPNAME(I),I=1,N
WATER
OIL
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*******************************************************************
CC                                                                  *
CC    OUTPUT OPTIONS                                                *
CC                                                                  *
CC*******************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*******************************************************************
CC                                                                  *
CC    RESERVOIR PROPERTIES                                          *
CC                                                                  *
CC*******************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
    1.0
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
```

```
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       4      4     4      4      0     0      0
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       2
CC
CC VARIABLE DEPTH (FT)
*----D111
     0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     1100
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
37500*0.35 884*0.50
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.134      0.0
CC
CC*******************************************************************
CC                                                                  *
CC    PHYSICAL PROPERTY DATA                                        *
CC                                                                  *
CC*******************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
```

```
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     2      2    2
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC
37500*0.35  884*0.21
CC
CC
*-- S2RWC
37500*0.16  884*0.12
CC
CC
*----S3RWC
37500*0.35  884*0.21
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW
37500*0.35  884*0.7
CC
CC
*-- P2RW
37500*0.78  884*0.92
CC
CC
*----P3RW
37500*0.35  884*0.7
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W
37500*3  884*1.1
```

```
CC
CC
*-- E2W
37500*2  884*1.3
CC
CC
*----E3W
37500*3  884*1.1
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    5.0    150
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
```

```
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
C
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
CC
CC
*---  KGOPT
      4
CC
CC
* -- IRKPPG        RKCUTPPG            DPPG         APPGS        PPGNS
DCRICWS     TOLPPGIN
      2          1000000000          0.0002888      10       -0.3         0.2
40
CC
CC
* --  APPGFR         PPGNFR
       10        -0.3
CC
CC
*---  ADPPGA         ADPPGB        RESRKFAC     TOLPPGRK
       0            0            0.1           1e-6
CC
CC
* ---- APPG1       APPG2     GAMCPG     GAMHFPG     POWNPG
        1e-6         1e-6        0.0         0.0        1.8
CC
CC*****************************************************************
CC                                                               *
CC    WELL DATA                                                  *
CC                                                               *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
```

```
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1     1    25      1       0.25     0.      3      1       15    0
CC
CC WELL NAME
*---- WELNAM
INJECTOR1
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
      2    50   25   2        0.25      0.     3     1         15       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     1000       1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.        0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    1000
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     0.3        0.005       0.005        0.005   0.005         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
     0.0001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
```

```
*----ID  QI(M,L)  C(M,KC,L)
     1    1000         1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.  1000.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     0.5      0.005       0.005        0.005   0.005         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1   1000         1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.          0.     0.   0.     0.   0.          0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
   1.0      0.005       0.005        0.005   0.005         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT    DCLIM          CNMAX   CNMIN
     0.0001   0.01          0.1   0.01
```

D-2. Input data for the complex fracture conduit model

```
CC*****************************************************************
CC                                                                *
CC    BRIEF DESCRIPTION OF DATA SET                               *
CC                                                                *
CC*****************************************************************
CC                                                                *
CC                                                                *
CC                                                                *
CC  LENGTH (FT) :    80           PROCESS :  PROFILE CONTROL      *
CC  THICKNESS (FT) :  30           INJ. PRESSURE (PSI) :    -     *
CC  WIDTH (FT) :    40            COORDINATES : CARTESIAN         *
CC  POROSITY :     0.25                                           *
CC  GRIDBLOCKS :  40 x 20 x 20                                   *
CC  DATE :                                                        *
CC                                                                *
CC*****************************************************************
CC
CC*****************************************************************
CC                                                                *
CC    RESERVOIR DESCRIPTION                                       *
CC                                                                *
CC*****************************************************************
CC
CC
*----RUNNO
Complex Conduit
CC
CC
*----HEADER
EDFM Synthetic Model, Complex fracture conduit, PPG treatment


CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISPC IREACT  ICOORD ITREAC ITC  IENG  IFRAC
        1    2    0      1      1     0      0    0      1
CC
CC NUMBER OF GRIDBLOCKS AND FLAG SPECIFIES CONSTANT OR VARIABLE GRID SIZE
*----NX   NY  NZ  IDXYZ  IUNIT
     40   20   20   0       0
CC
CC NUMBER OF FRACTURE GRIDBLOCKS
*----NF  MAXF
     85   50
CC
CC  VARIABLE GRID BLOCK SIZE IN X
*----DX         DY          DZ
     2          2           1.5
CC
CC TOTAL NO. OF COMPONENTS, NO. OF TRACERS, NO. OF GEL COMPONENTS
*----N   NTW  NG
     14   0   6
CC
CC
*---- SPNAME(I),I=1,N
WATER
OIL
```

```
none
none
SALT
none
none
none
none
none
none
none
none
ppg
CC
CC FLAG INDICATING IF THE COMPONENT IS INCLUDED IN CALCULATIONS OR NOT
*----ICF(KC) FOR KC=1,N
   1  1  0  0  1 0  0 0 0 0 0 0 0 1
CC
CC*****************************************************************
CC                                                                *
CC    OUTPUT OPTIONS                                              *
CC                                                                *
CC*****************************************************************
CC
CC
CC  FLAG FOR PV OR DAYS FOR OUTPUT AND STOP THE RUN
*----ICUMTM  ISTOP
       1     1
CC
CC FLAG INDICATING IF THE PROFILE OF KCTH COMPONENT SHOULD BE WRITTEN
*----IPRFLG(KC),KC=1,N
     1  1  0  0  0  0 0 0 0 0 0 0 0  1
CC
CC FLAG FOR PRES,SAT.,TOTAL CONC.,TRACER CONC.,CAP.,GEL, ALKALINE PROFILES
*----IPPRES IPSAT IPCTOT IPGEL  ITEMP
      1      1      1      1    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES
*----ICKL IVIS IPER ICNM  ICSE
      0     1    0    0    0
CC
CC FLAG FOR WRITING SEVERAL PROPERTIES TO PROF
*----IADS  IVEL IRKF IPHSE
      0     0    1    0
CC
CC*****************************************************************
CC                                                                *
CC    RESERVOIR PROPERTIES                                        *
CC                                                                *
CC*****************************************************************
CC
CC
CC MAX. SIMULATION TIME (PV)
*---- TMAX
    1.0
CC
CC ROCK COMPRESSIBILITY (1/PSI), STAND. PRESSURE(PSIA)
*----COMPR   PSTAND
      0.      14.7
CC
CC FLAGS INDICATING CONSTANT OR VARIABLE POROSITY, X,Y,AND Z PERMEABILITY
```

```
*----IPOR1 IPERMX IPERMY IPERMZ  IMOD  ITRNZ  INTG
       4      4     4      4      0     0      0
CC
CC FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION
*----IDEPTH  IPRESS  ISWI
      0        0       2
CC
CC VARIABLE DEPTH (FT)
*----D111
     0
CC
CC CONSTANT PRESSURE (PSIA)
*----PRESS1
     1100
CC
CC CONSTANT INITIAL WATER SATURATION
*----SWI
16000*0.35 85*0.50
CC
CC CONSTANT CHLORIDE AND CALCIUM CONCENTRATIONS (MEQ/ML)
*----C50       C60
     0.134      0.0
CC
CC*******************************************************************
CC                                                                  *
CC    PHYSICAL PROPERTY DATA                                        *
CC                                                                  *
CC*******************************************************************
CC
CC
CC CMC
*----  EPSME
      .0001
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 1
*----HBNS70 HBNC70 HBNS71 HBNC71 HBNS72 HBNC72
     0.     .030    0.   .030     0.0   .030
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2XOPT SALINITY
CC FOR ALCOHOL 2
*----HBNS80 HBNC80 HBNS81 HBNC81 HBNS82 HBNC82
     0.     0.     0.     0.     0.     0.
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
*----CSEL7  CSEU7  CSEL8  CSEU8
     .65   .9   0.     0.
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
*----BETA6  BETA7  BETA8
     0.0    0.    0.
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
*----IALC  OPSK7O  OPSK7S  OPSK8O  OPSK8S
     0     0.      0.      0.      0.
CC
CC NO. OF ITERATIONS, AND TOLERANCE
*----NALMAX   EPSALC
     20       .0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
*----AKWC7   AKWS7  AKM7  AK7     PT7
```

```
     4.671   1.79   48.   35.31   .222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
*----AKWC8   AKWS8  AKM8  AK8     PT8
     0.      0.     0.    0.      0.
CC
CC
*--- IFT MODEL FLAG
      0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11  G12     G13   G21   G22    G23
     13.  -14.8   .007  13.2   -14.5  .010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*----XIFTW
     1.477
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*----ITRAP   T11        T22        T33
     0       1865.      28665.46      364.2
CC
CC REL. PERM. AND PC CURVES
*---- IPERM    IRTYPE
        0       0
CC
CC FLAG FOR CONSTANT OR VARIABLE REL. PERM. PARAMETERS
*----ISRW  IPRW  IEW
     2      2    2
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----S1RWC
16000*0.35  85*0.31
CC
CC
*-- S2RWC
16000*0.12  85*0.1
CC
CC
*----S3RWC
16000*0.35  85*0.21
CC
CC CONSTANT RES. SATURATION OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----P1RW
16000*0.35  85*0.5
CC
CC
*-- P2RW
16000*0.85  85*0.95
CC
CC
*----P3RW
16000*0.35  85*0.7
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*----E1W
16000*3  85*1.4
CC
CC
*-- E2W
```

```
16000*2  85*1.2
CC
CC
*----E3W
16000*3  85*1.1
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*----VIS1   VIS2  TEMPV
     1.0    2.5    150
CC
CC VISCOSITY PARAMETERS
*----ALPHA1 ALPHA2  ALPHA3  ALPHA4  ALPHA5
     0.0     0.0      0.0   0.000865    4.153
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*----AP1     AP2     AP3
     0.0001   0      0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1  SLOPE
     10    .01   .0
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC  GAMHF  POWN    IPMOD   ishear  rweff   GAMHF2  iwreath
     10.0        0.0    1.8     0       0       0.25    0      0
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK    CRK    RKCUT
     1      1.    1      0.     0.0  10
CC
CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,AND 8 , AND GRAVITY FLAG
*----DEN1  DEN2    DEN3     DEN7 DEN8  IDEN
   62.899  49.857  62.399  49.824  0  2
CC
CC  FLAG FOR CHOICE OF UNITS ( 0:BOTTOMHOLE CONDITION , 1: STOCK TANK)
*-----ISTB
      0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7,AND 8
*----COMPC(1)  COMPC(2)  COMPC(3)  COMPC(7)  COMPC(8)
     0.        0.        0.        0.        0.
CC
CC CONSTANT OR VARIABLE PC PARAM., WATER-WET OR OIL-WET PC CURVE FLAG
*----ICPC   IEPC  IOW
     0       0   0
CC
CC CAPILLARY PRESSURE PARAMETERS, CPC
*----CPC
   0.
CC
CC CAPILLARY PRESSURE PARAMETERS, EPC
*---- EPC
      2.
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 1 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0  0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 2 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
```

```
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0 0.0
CC
CC MOLECULAR DIFFUSIVITY OF KCTH COMPONENT IN PHASE 3 (D(KC),KC=1,N)
*----D(1) D(2) D(3) D(4) D(5) D(6)
     0.   0.   0.   0.   0.   0.  0.0  0.0  0.0  0.0  0.0  0.0 0.0  0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1)     ALPHAT(1)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2)     ALPHAT(2)
     0.0          0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3)     ALPHAT(3)
     0.0          0.0
C
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----AD31     AD32  B3D    AD41   AD42  B4D  IADK, IADS1, FADS refk
     0.        .0  1000.  0.672   0.0  1      0      0      0   0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----QV     XKC   XKS  EQW
      0     0.    0.   804
cc
cc
*---  KGOPT
      4
CC
CC****particle size, swelling ratio
* -- IRKPPG        RKCUTPPG            DPPG         APPGS        PPGNS
DCRICWS     TOLPPGIN
      2          1000000000          0.0002888      10       -0.3         0.4
40
CC
CC****fittin equation for resistance factor
* --  APPGFR         PPGNFR
       20        -0.3
CC
CC
*---  ADPPGA         ADPPGB        RESRKFAC     TOLPPGRK
       0             0            0.2           1e-6
CC
CC
* ---- APPG1       APPG2     GAMCPG     GAMHFPG     POWNPG
        1e-6         1e-6        0.0         0.0        1.8
CC
CC*****************************************************************
CC                                                                *
CC    WELL DATA                                                   *
CC                                                                *
CC*****************************************************************
CC
CC
CC TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
*----NWELL   IRO   ITIME  NWREL
      2      2      1      2
CC
CC WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
```

```
*----IDW   IW    JW    IFLAG    RW     SWELL  IDIR   IFIRST  ILAST  IPRF
      1     1    10      1       0.25     0.      3      1       20    0
CC
CC WELL NAME
*---- WELNAM
INJECTOR1
CC
CC ICHEK MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK   PWFMIN   PWFMAX    QTMIN    QTMAX
      0      0.0       10000    0.0     50000.
CC
CC WELL ID, LOCATION, AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
*----IDW  IW   JW   IFLAG    RW     SWELL  IDIR  IFIRST   ILAST    IPRF
      2    40   10   2        0.25      0.     3     1         20       0
CC
CC WELL NAME
*---- WELNAM
PRODUCER1
CC
CC MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
*----ICHEK  PWFMIN   PWFMAX  QTMIN   QTMAX
      0     0.0      10000.   0.0     -50000.
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1     600       1.   0.  0.     0.   0.1342282    0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
     1     0.         0.   0.  0.     0.   0.           0.    0.    0.    0.
0.   0.   0.   0.   0.
CC
CC ID, BOTTOM HOLE PRESSURE FOR PRESSURE CONSTRAINT WELL (IFLAG=2 OR 3)
*----ID   PWF
     2    800
CC
CC CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
*----TINJ    CUMPR1   CUMHI1     WRHPV   WRPRF      RSTC
     0.3        0.005       0.005        0.005   0.005         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT      DCLIM     CNMAX   CNMIN
     0.0001    0.01     0.1     0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1    600         1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.  2000.
```

```
     1    0.           0.      0.   0.      0.   0.           0.     0.     0.     0.
0.   0.   0.   0.   0.
     1    0.           0.      0.   0.      0.   0.           0.     0.     0.     0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
     0.5      0.005       0.005        0.005   0.005         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT     DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS ( WATER INJ.)
*---- IRO ITIME IFLAG
       2   1     1  2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*----NWEL1
     0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*----NWEL1   ID
     1        1
CC
CC ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*----ID  QI(M,L)  C(M,KC,L)
     1   600         1.     0.   0.     0.   0.1342282   0.    0.    0.    0.
0.   0.   0.   0.   0.
     1    0.           0.      0.   0.      0.   0.           0.     0.     0.     0.
0.   0.   0.   0.   0.
     1    0.           0.      0.   0.      0.   0.           0.     0.     0.     0.
0.   0.   0.   0.   0.
CC
CC CUM. INJ. TIME , AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*----TINJ   CUMPR1  CUMHI1(PROFIL)  WRHPV(HIST) WRPRF(PLOT) RSTC
   1.0      0.01       0.01        0.01   0.01         1
CC
CC FOR IMES=2 ,THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. COURANT NO.
*----DT    DCLIM          CNMAX   CNMIN
     0.0001   0.01           0.1   0.01
```

D-3. The impact of having the created fractures in the synthetic models

Slanted fracture plane model

Figure D-1 shows the comparison of the oil recoveries from waterflooding the synthetic model with and without the slanted fracture plane. The waterflood recovery from the model without the fracture plane was 61.81% while the recovery from the model with the conduit was only 55.77%. The impact of having the slanted fracture plane on waterflood recovery in this case was as significant as 6.04% reduction.

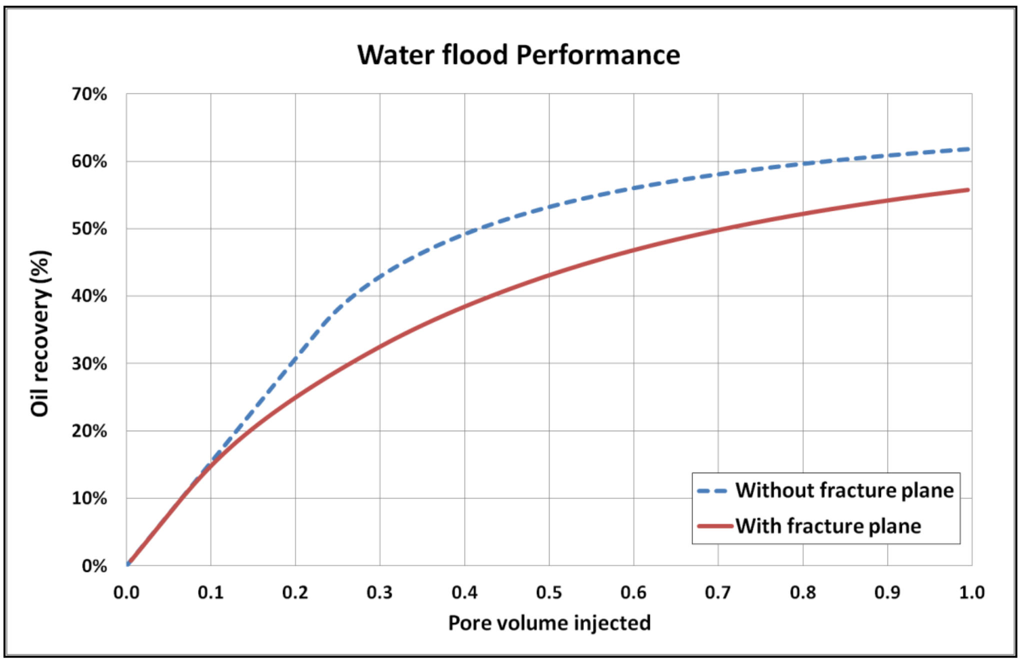

Figure D - 1. Comparison of the waterflood performance of a reservoir with and without a slanted fracture plane

Complex fracture conduit model

Figure D-2 shows the comparison of the oil recoveries from waterflooding the synthetic model with and without the complex conduit. The waterflood recovery from the model without the conduit was 73.57% while the recovery from the model with the conduit was 73.28%. The impact of having the complex conduit on waterflood recovery in this case was only 0.29% reduction.

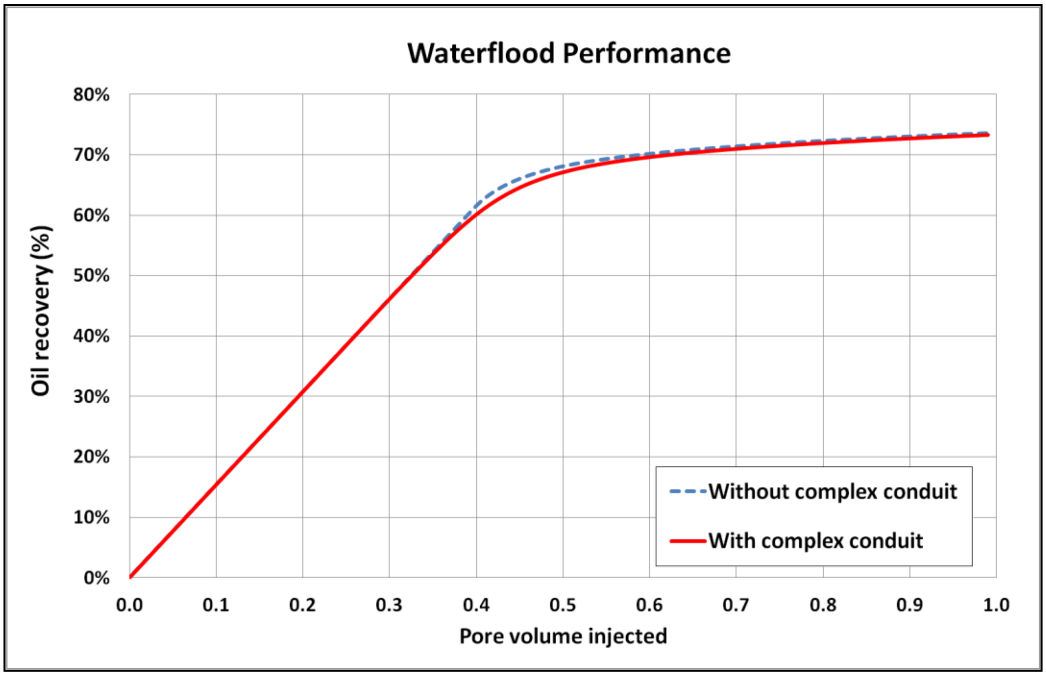

Figure D - 2. Comparison of the waterflood performance of a reservoir with and without a complex fracture conduit

Nomenclature

English Symbols

A	Area of fracture cell inside the grid block
$A_{PPG,1}$	Model input parameter for PPG viscosity calculation in UTGEL
$A_{PPG,2}$	Model input parameter for PPG viscosity calculation in UTGEL
a_{kp}	Model input parameters for resistance factor calculation in UTGEL (corresponding to APPGFR in INPUT files)
a_p	Model input parameter for swelling equation in UTGEL (corresponding to APPGS in INPUT files)
C_{Kl}	Concentration of component K in phase l
C_K^o	Volume-weighted component compressibility
C_M	Microgel concentration, which is defined as the amount of microgel per unit volume of solution and usually expressed in terms of mass per unit volume
C_{pl}	Phase l heat capacity at constant pressure
C_{PPG}	PPG concentration in aqueous phase
C_r	Rock compressibility
C_{SEP}	Effective salinity in meq per liter which takes into account the combined effect of anions and divalent cations
C_t	Total compressibility
C_{vl}	Phase l heat capacity at constant volume
C_{vs}	Rock heat capacity at constant volume
$\tilde{C}$	Overall volumetric concentration of component K
$\hat{C}_K$	Adsorbed concentration of component K
d	Normal distance between center of matrix grid block and fracture cell
$\vec{\vec{D}}_{KL}$	Dispersive flux of component K
k	Permeability or harmonic average of the permeabilities
$k_{r\iota}$	Relative permeability of phase l

$\bar{k}$	Average permeability
K_H	Huggins constant
L	Length of intersection line (between 2 fractures) bounded in a grid block
M	Mobility ratio
M_l	Volume of gel after swelling
M_s	Volume of dry gel before swelling
n_{kp}	Model input parameters for resistance factor calculation in UTGEL (corresponding to APPGFR in INPUT files)
n_p	Number of components
n_p	Model input parameter for swelling equation in UTGEL (corresponding to PPGNFR in INPUT files)
OOIP	Original oil in place
P_α	Model input parameter for effective viscosity calculation in UTGEL
ppm	Part per million
PV	Pore volume injected
q	Flow rate in cu.ft/day
q_H	Enthalpy source term per bulk volume
Q_L	Heat loss
r_h	Pore throat radius
R_K	Injection or production rate for component K per bulk volume K
R_{kfp}	Permeability reduction factor
$R_{kfp,factor}$	Model input parameter for resistance factor calculation in UTGEL
$R_{kfp,max}$	Maximum permeability reduction
RF	Resistance factor or permeability reduction factor
RRF	Residual resistance factor
S_l	Saturation of phase l
SF	Swelling ratio
T	Reservoir temperature

T	Transmissibility factor
V_{DP}	Dykstra Parsons coefficient

Greek Symbols

λ_T	Thermal conductivity
$[\eta]$	Zero-shear intrinsic viscosity
ϕ	Porosity
ρ_K	Density of pure component K
$\vec{u}_l$	Volumetric flux of phase l
μ_M	Effective viscosity of microgel solution at low shear rate
μ_M^0	Microgel solution viscosity at zero shear rate
μ_o	Oil viscosity
μ_s	Solvent viscosity
μ_w	Water viscosity
$\|\mu_\iota\|$	Magnitude of flux,
ω	Fracture aperture
$\dot{\gamma}_c$	Shear rate correction
$\dot{\gamma}_{eq}$	Equivalent shear rate
$\dot{\gamma}_{1/2}$	Model input parameter for effective viscosity calculation in UTGEL

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