STEAM ASSISTED GRAVITY DRAINAGE

By

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Steam Assisted Gravity Drainage
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CERTIFICATE

This is to certify that Megha Thapliyal , Pankaj Bhatt & Shweta Negi, students of B.Tech-Applied Petroleum Engineering (Gas Specialization) have written their thesis on "Steam assisted Gravity Drainage" under my supervision and have successfully completed their project within the stipulated time.
They have demonstrated high performance levels and dedication during the completion of their thesis.

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ABSTRACT

Steam-assisted gravity drainage (SAGD) is a promising approach for recovering heavy and viscous oil resources. In SAGD, two closely-spaced horizontal wells, one above the other, form a steam-injector and producer pair. The reservoir oil is heated by the injected steam and drains to the producer under the effect of gravity. The success of steam-assisted gravity drainage has been demonstrated by both field and laboratory studies mostly based on homogeneous reservoirs and reservoir models. A comprehensive understanding of the effects of reservoir heterogeneities on SAGD performance, however, is required for wider and more successful implementation. This dissertation presents an investigation of the effects of reservoir heterogeneities on SAGD. In addition, two potential methods, hydraulic fracturing and mobility control using foamed steam, are proposed and reported here to enhance SAGD performance, especially for heterogeneous reservoirs.

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INTRODUCTION

Like most oil fields in the light of the world have passed their peak production, the industry focus has shifted in heavy oil. Large amounts of heavy and extra heavy oil (bitumen) resources have been discovered worldwide. For example, recently in India in the western region of Rajasthan, a heavy crude oil crude oil known as Jodhpur was found in the porous sand formation of structure in the basin Bhagawala Bikaner-Nagamo. The total area of 70 square km of the basin is about 600 million years old Cambrian. Reserves Bhagawala structure is estimated at 30 million tonnes and would be around 80 million tonnes if neighboring structures also proved to be oil. And worldwide, it is estimated that the heavy oil of more than 1.8 billion barrels is present in Venezuela, 1.7 billion barrels in Alberta, Canada, and 20-25 billion barrels on the North Slope of Alaska USA. Since heavy oil has high viscosity, typically greater than 100 cp at reservoir conditions, oil flows slowly through the formation. Therefore, economic recovery and efficient resource of heavy oil presents a significant challenge. In order to recover unconventional heavy oil efficiently, effectively reducing the viscosity of heavy oil is required. For this purpose thermal methods have been developed extensively in recent decades. The fundamental principle of thermal methods is to heat the reservoir and thus increase the temperature of oil to reduce its viscosity as the viscosity decreases with increasing temperature. Thermal methods include conventional cyclic steam stimulation, steam flooding and in-situ combustion. With recent advances in horizontal well technology, a technique more-recently developed, steam assisted gravity drainage (SAGD) has become one of the most effective techniques for the recovery of the massive oil heavy. The objective of this project is to examine the SAGD performance in heterogeneous reservoirs and improve their performance through the deployment of hydraulic fractures and combining the use of aqueous foam for mobility control with steam injection.

The SAGD concept originally proposed by Butler and colleagues, is shown schematically in the below figure. In this process, two horizontal wells are placed near the bottom of a formation, with one over the other to a short vertical distance (4-10 m). Steam is injected continuously into the upper well, and rises in the formation, forming a steam chamber. Cold oil around the steam chamber is heated primarily by thermal conduction. As the temperature increases, the oil becomes mobile and flows with the condensate along the border to the lower house, so it works as a producer. SAGD technology has many advantages over other heat treatment methods, including conventional methods of steam flooding. SAGD overcomes the shortcomings of the override of steam by using only gravity as the driving mechanism.

This leads to a stable displacement and high recovery of oil. Moreover, in the SAGD process, hot oil stays hot and is movable as it flows toward the production well, while in conventional steam flooding, the oil displaced from the steam chamber is cooled and it is difficult to push to the production well.

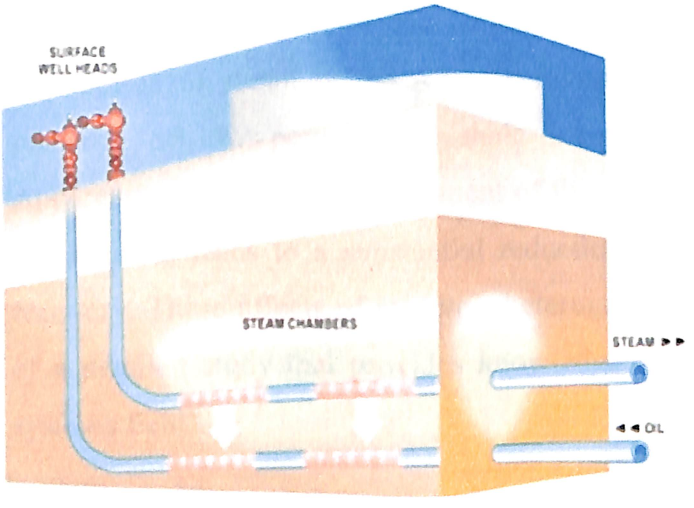


Figure 1: Schematic of a SAGD process

SAGD several field pilots were carried out in western Canada in late 1980 and the results reported in the literature are promising. Reservoir of the chosen pilot field, however, usually consists of high quality, homogeneous formations. In actual, no reservoir is homogeneous due to natural geological features, such as shaly, faults and fractures. The geology of the formation presents a major concern in field applications SAGD. The heterogeneity introduced by shale barriers and other geological features play an important role in the spread of steam and therefore affects the overall performance of a SAGD process. For example, steam often selectively channels into high permeability zones in a multi-phase shift due to their greater mobility compared with the oil and water. In addition, due to the use of a long horizontal nozzle, the variation along the injectivity due to either local heterogeneity makes it difficult to develop an even steam injection profile. As a result, the steam chamber is formed only around the well segment which is surrounded by high permeability formation.

Figure 2 shows an example of a field of vapor chambers developed unevenly, observed in the Christina Lake SAGD project using a 4D seismic imaging technique. There are four pairs and active, A1-A4 (A5 and A6 and pairs, have limited the production of histories for the analysis.) The color in Figure shows the seismic amplitude difference between two seismic surveys conducted before and after steam injection. The steam chamber development is along most of the length and, although not completely uniform in the lateral direction, for A1, A2 and A4 areas, as is evident in Figure. For pair A3, however, the steam appears to cover about two-thirds of the length on the heel side of the area A3. The pattern of distribution of steam in the A3 was found to be in high degree of correlation with the presence of low permeability shale identified by high resolution Crosswell seismic. Apparently, the uneven development of the steam chamber as in the case of A3 as shown in the figure 2 leads to a substantial reduction in the rate of oil production and overall oil recovery. These effects of reservoir heterogeneities effecting SAGD performance is worthy of a detailed study that provides knowledge of accurate and reliable predictions for such systems field.

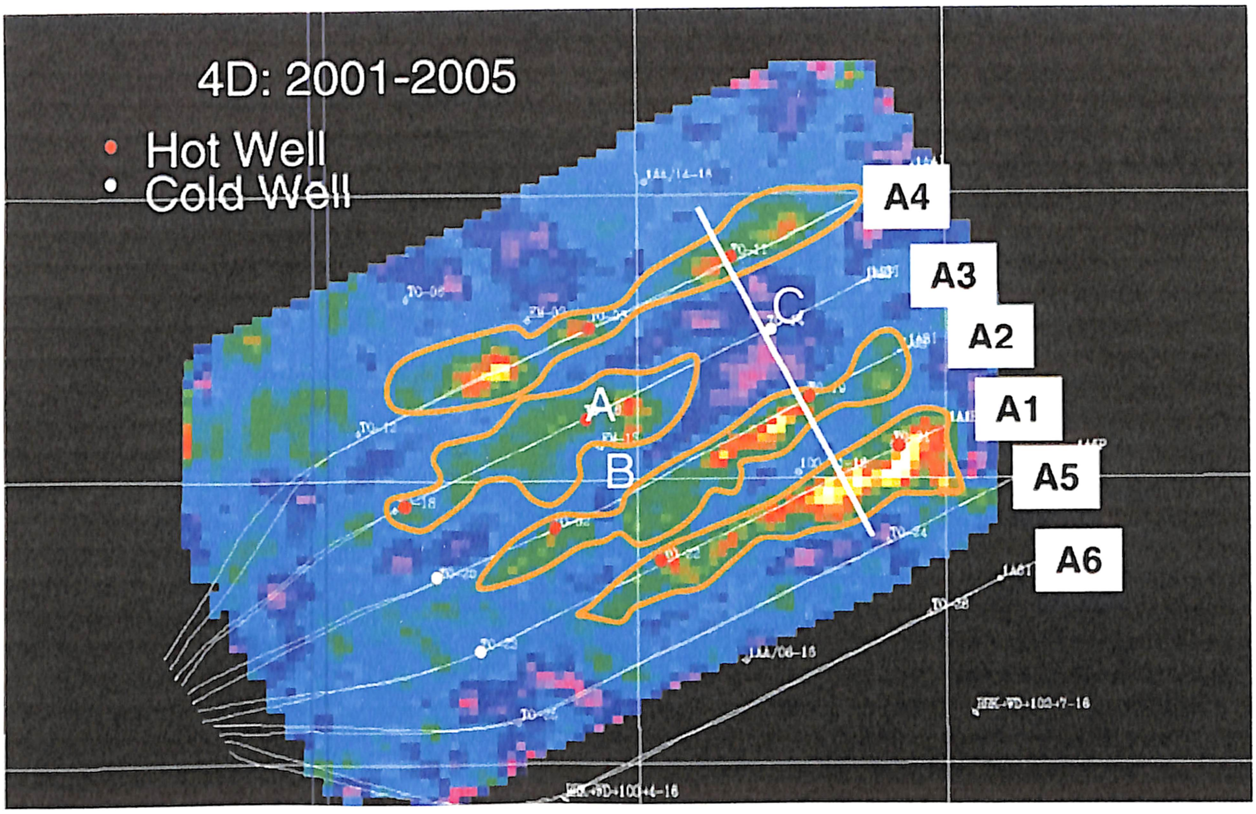


Figure 2: 4D seismic amplitude image of steam chamber growth at the Christina Lake SAGD project

The second aspect of this work is motivated by the need to improve SAGD in heterogeneous reservoirs. This improvement is crucial to expand the application of SAGD and produce the huge, discovered heavy oil / bitumen resources worldwide. In this paper, we propose hydraulic fracturing in SAGD conventional configuration to mitigate the lack of vertical communication accompanying the deposits with a high percentage of shale. Moreover, in order to achieve a more uniform growth of the steam chamber and improved process efficiency, introducing a new concept of foam using SAGD (FA-SAGD), in which foamed steam is injected into the formation in SAGD mode. The foam is often suggested to improve sweep efficiency in the processes of multiphase displacement and provides a potential approach to improve the performance of SAGD. Aqueous foams are formed by the dispersal of wet gases within a continuous phase of liquid surfactant loaded either by alternating or co injecting gas and surfactant solution in porous media. Because the foam has significant flow resistance in porous media, foaming the steam overcomes the adverse mobility of steam injection and possibly improves the steam chamber development in SAGD process.

There are several theories of foam modeling developed in recent decades, but has some limitations. Requirement of an additional equation for the foam bubbles adds complexity to the application of the models, and also increases the computational cost of simulation. Therefore, we must develop a more efficient model of the foam and then simulate and evaluate the process of SAGD.

Dissertation Outline

The report reviews the literature on two research topics relevant to this work, SAGD and aqueous foam in porous media. In the first section of this topic, the concept of SAGD development, processing mechanisms and laboratory and field studies are presented. The focus is on several major issues revealed from SAGD field operations, including reservoir heterogeneity and steam trap application. Several configurations modifying SAGD and SAGD derivatives aimed at accelerating and improving the efficiency of the SAGD process is reviewed. The second section describes previous research and efforts made to understand and predict the behavior of foam in porous media. In that section, we first review the foaming, transport, and mechanisms of destruction. Hydraulic fracturing is discussed in the next section as a potential approach to accelerate the growth of steam chamber and thus improve performance of SAGD for deposits with the poor vertical communication. The next section introduces the concept foam assisted SAGD foam and has an evaluation of FA-SAGD.

The above mentioned sections are then followed by an analytical case study.

In discussing the results, we comment on one major concern of live steam breakthrough with hydraulically-induced fractures that penetrate injection and production wells. Finally, draw conclusions and make recommendations for future work in the last section.

Literature Review

Extensive research efforts have been devoted to understand the physical mechanisms and the development of mechanistic theories of SAGD and aqueous foam flow in porous media. In this section, we review previous work on these two issues.

1. Introduction to Steam-Assisted Gravity Drainage

1.1 SAGD Concept and Mechanics

The SAGD concept was originally introduced by Butler and his former colleagues. As described in the previous section, the main characteristic of SAGD depends on the introduction of steam into a reservoir to form a steam chamber and hot oil production using two horizontal wells by gravity.
Since oil production comes mainly from the chamber or heated oil interface, steam chamber growth is responsible for oil production. Therefore, a fair amount of research has focused on the analysis of steam chamber development and associated physical processes, including flow condition at the top of the steam chamber and the flow of direct current along the slope of the steam chamber. Butler (1994) observed separate and ragged steam fingers, rather than a flat front at the top of steam chamber during the rise of the chamber. Butler attributed the emergence of these fingers to the instability caused by the slight increase of steam under heavy oil. In his theory of steam fingering, Butler described the steam chamber as a dome-shaped structure with the fingers of steam coming out of its upper surface. Steam flows in these fingers, it condenses on its surface, and heated oil around the fingers. Warm oil drains down around the perimeter of the fingers in the steam chamber and meanders with the countercurrent flow of steam. They also reported the growing instability of the interface of vapor chamber near the roof, i.e. steam fingering with intermittent steam injection in the horizontal bottom case. Nasr et al. studied the steam-liquid countercurrent flows and co current for different permeabilities. They performed two dimensional scaled at gravity drainage experiments designed to represent the heavy oil / bitumen reservoir. They made visual observations of the development of the steam chamber during the experiments and compared with numerical model predictions. In his conclusion, Nasr et al. indicated that the

upstream water vapor compared to the speed of propagation is not a linear function of permeability. while the speed of propagation, for a given permeability, is a linear function of time. They also noted that for the same permeability, the countercurrent vapor front propagates much slower than the cocurrent front. It attributes the difference in the countercurrent and cocurrent relative permeability to the results of viscous coupling between phases.

Understanding heat transfer through the steam chamber is crucial for the analysis and modeling of the steam chamber growth and therefore the prediction of oil production and process efficiency. In the original concept of SAGD, Butler implies that the transfer of heat to cool oil ahead of the steam chamber is only by conduction. Farouq-Ali (1997) criticized this assumption and argued that the strong flow of condensate from the steam and oil along the slope vapor chamber is expected to result in more dominant convection. His statement was supported by the results of numerical simulations presented in Ito and Suzuki's (1999) paper. In response, Edmunds (1999) analyzed the associated change in enthalpy of the fluid flowing within and along the steam chamber. He stated that liquid water could carry and deposit 18% of the heat of condensation of water itself. Another 4% of the latent heat is transferred by convection due to the flow of oil and the remaining 78% would be transported by conduction. Edmund's (1999) evaluation also showed that the convection function to rationalize because the water being almost parallel to the isotherms is less than 5%. Therefore, Edmunds (1999) stated that except for the very near vicinity of the liner or anywhere live steam penetrates, heat transfer in the mobile zone is dominated by conduction, not convection.

1.2 SAGD Prediction

Accurate prediction of SAGD performance in a reservoir is of vital importance for the selection of successful projects, efficient process optimization and real field applications. SAGD based on the concept described in the previous section, Butler developed an analytical model to predict the type of drainage. Using the Darcy equation to gravity drainage bitumen countercurrent mobilized (or heavy oil) and taking into account the steam chamber geometries; Butler developed a theory of gravity drainage and derivatives semi analytical numerical models. The hypothesis's assumptions include that only steam flows in the steam chamber, the oil drain along the vertical border of steam chamber, steam pressure is constant in the steam chamber, residual oil saturation, and heat transfer ahead of the steam chamber of cold oil is only by conduction.

1.3 SAGD Field Pilots and Major Concerns

The first field test of SAGD was AOSTRA Underground Facility (UTF) in the Athabasca, project was initiated on the proposal of Butler. The project started in 1988 with Phase A involving three pairs of short wells which are closely spaced (50 m long and 25 m horizontal distance). The success of this pilot project led to two successive phases, phase B and D, where five additional well pairs 500 m long and 70 m apart were drilled. This pilot was operated until June 2004 and was reported to be successful with the performance against expectations, for example, a final recovery of more than 65% and a steam oil ratio (OSR) of 0.42. Another example of a field SAGD project is the field in North Tangleflags in the Lloydminster area that has been operated by the scepter resources since 1989. This project uses horizontal wells combined with mostly multiple vertical injectors. It was reported that more than 400,000 m3 of oil was produced with a COSRA of 0.32 over the life of the operation.

Encouraged by the promising results of field testing, more than ten commercial SAGD projects have been operating in Canada, primarily in the Athabasca area in the last two decades. Recently, Jimenez presented a detailed review of field performance of existing SAGD projects in Canada. He analyzed a total of 32 pads from eight different SAGD operations. In his conclusion, Jones stressed the geology and the operation as key parameters for the success of SAGD process. He said the final average SAGD recovery is expected to be about 60 to 70% dry COSRA ranging from 0.30 to 0.50. Despite the success of some projects, field applications of the SAGD process have highlighted several issues of great importance for the retrieval performance. Farouq Ali noted that the geology of the training could have a profound influence on the growth of steam chamber. Another major concern in SAGD applications and controls are, or more specifically, the steam trap control in wells to prevent the production of live steam.

1.4 Effect of Reservoir Heterogeneity

Due to the nature of the geology of deposits, the heterogeneity always exists in a formation, sometimes with significant variations even within the same field. As illustrated above, the limited growth of vapor chamber and observed using 4D Crosswell seismic imaging in the Christina Lake SAGD project provides a good example demonstrating the importance of the effect of reservoir heterogeneity on SAGD performance. Another example is the UTF Phase A, where the steam seen in the UTF Phase A flattened and expanded sideways instead of vertically on top of training. Farouq-Ali (1997) was attributed to small differences in the characteristics of the training. In recent decades, the role of reservoir heterogeneities in the steam chamber development for a SAGD process has been investigated numerically and experimentally. Joshi and Threlkeld (1985) reservoirs with barriers of shale and compared the effects of various systems and settings, as well as vertical fractures experimentally. Indicating that vertical fractures perpendicular to a horizontal injector improves the oil recovery rate compared with a horizontal injector / producer horizontal. Yang and Butler (1992) conducted experiments SAGD with deposits of two types: reservoirs with horizontal layers of different permeability and reservoirs with thin layers of shale. They observed faster production when a higher permeability layer located above a lower permeability layer than a lower permeability layer located above a higher permeability layer. For the effect of shale, they compared the experimental runs with horizontal barriers of different lengths placed in their two dimensional scaled reservoir model. They found that a short horizontal barrier does not significantly affect the overall performance of the SAGD process. The presence of a barrier decreases the production time, but in some configurations, not as serious as expected.

Bagci (2004) reported experimental studies of the effect of fractures and well configurations in the SAGD process. He used a 30 cm × 30 cm × 10 cm rectangular shaped model box equipped with 25 thermocouples and temperature profiles obtained in time to visualize the effect of fractures in the steam chamber growth. Their experimental results indicate that vertical fractures improved SAGD. It also showed increased SOR during the initial stage of fracture model than in the reservoir of uniform permeability. Therefore, said the vertical fracture could be used to improve the rate of initial oil production.

1.5 Steam Trap Control

Prevent steam breakthrough in the SAGD process is critical to ensure energy efficiency and thus the process economics. Control of the steam trap is commonly used as an operational control to reduce or avoid withdrawal of steam from the steam zone in the reservoir. Das (2005) identified three main benefits of control steam trap SAGD process: 1) energy conservation and reduction of SOR, 2) reducing the high steam flow into the well which adversely affects the surface facilities and capacity of well, and 3) reduction of the sand and the movement of fines through the liner that may cause erosion. The control of the steam trap is generally achieved by adjusting the extraction rate of production fluids and the produced fluid temperature remains below the saturation temperature of steam by a preset subcooling temperature. The question of subcooling has attracted much attention from researchers studying SAGD. Based on experimental observations, Joshi and Threlkeld (1985) stated that production temperatures below about 20 _C steam temperatures are usually sufficient to raise a leg over the final liquid producers, without short-circuiting of steam.

In a typical SAGD, however, short vertical spacing (about 5 m) between the nozzles and produces makes it difficult in field operations to maintain subcooling provided to producers, ie no production of live steam. Farouq-Ali (1997) expressed concern that the operation of wells in the area with steam trap control is difficult. Das (2005) also referred in his speech that it is very difficult in the field to control steam breakthrough due to the uneven nature of the heterogeneity of the deposit and the path too. To minimize steam breakthrough, proposed SAGD alternative configuration in which the injection and the flow of liquids produced in the same direction and therefore the pressure drop along the segment and between injectors and producers is more uniform. This new configuration, however, requires multiple pads, causing additional capital expenditures.

1.6 SAGD Improvement

It is believed that the steady growth of vapor chamber is necessary for the success of the SAGD process. In order to improve the performance of SAGD, researchers have proposed several modifications to the classic configuration, resulting in a series of processes derived. These changes are mainly focused on accelerating the growth of steam chamber and improved heat efficiency. According to the mechanisms of changes in SAGD, Albahlani and Babadagli (2008) in a recent review modified SAGD processes classified into two categories: geometric attempts and chemical attempts. Geometric attempts approach to the different alternating pressure points related to the placement of wells to hold the steam expansion chamber. Polikar et al. (2000), for example, proposed a process called Fast-SAGD process that utilizes additional single horizontal well alongside the SAGD well pair. Single horizontal wells (called offset wells) are operated in a cyclic steam stimulation (CSS) so after the steam chamber anchoring at the SAGD well pair has fully developed and has reached the top of the pay zone. CSS operation at the offset wells creates a pressure sink in the lower part of the reservoir through which steam is driven downward against its tendency to rise upward due to gravity. This helps the steam to expand laterally. From their two-dimensional simulation studies, Shin and Polikar (2006) concluded that the Fast- SAGD has a lower cumulative steam-oil ratio due to thermal efficiency and higher oil recovery as much as 34% greater than conventional SAGD. Stalder (2007) describes an alternative SAGD configuration was termed as the Cross-SAGD (XSAGD). In XSAGD, a series of horizontal injection wells are placed perpendicular rather than parallel as in SAGD, producers, creating a grid of wells. During the process, the operation of connecting or flow restriction applies to producers and injectors to cross the points after a strategic time and therefore to increase the drainage rate and minimize steam short-circuiting. Stalder (2007) 's comparison and XSAGD SAGD simulation showed accelerated recovery and increased thermal efficiency XSAGD. He also noted two penalties with the concept XSAGD. First. in the first stage, only portions of the wells near the crossing points are effective for steam chamber growth, so with a limited initial production rate. Second, connecting the complex operation requires an additional cost and is a serious practical problem of operations. The chemical approach attempts to improve the efficiency of heat and reduce the surface tension of water and oil for increased production. Examples include non-condensable gases (NCG) and expansion of solvent SAGD (ES-SAGD). In the former, noncondensable gas is coinjected with steam into the reservoir. ES-SAGD was developed by Nasr et al. (2003). The essential idea is co-injection ES-SAGD oil additive (solvent) with steam at low concentration. Solvent, normally existing in its vapor phase at high steam injecting temperature, condenses with the steam on the boundary of the steam chamber causing oil dilution and reduced viscosity as well.

2. Feature of the SAGD Process

In practice, the SAGD process is normally initiated with a preheating period to overcome the difficulty of steam injection due to extremely unfavorable mobility ratio. During the preheating period, steam is circulated in the tubing and out of the annulus for both horizontal wells, thus heating the surrounding oil by conduction. Once thermal communication is established between wells and the oil in the inter-well region becomes mobile, steam is injected into the reservoir to develop a chamber above the wells. An idealized steam chamber in a homogeneous reservoir is shown schematically in Figure 3. The development of this inverse-triangularly-shaped steam chamber involves complicated steam condensate flows and thermal processes. Injected steam rises within the chamber under buoyancy forces and flows continuously to the perimeter of the chamber, where it condenses and releases a large amount of latent heat. The heat is transferred, by both conduction and convection, first to the condensate that flows inside the steam chamber, and then the adjoining oil. The mobilized oil and the condensate drain by gravity along the steam chamber toward the production well. As the oil is removed and more steam is injected, the boundary of the steam chamber expands upwards and sideways.

Steam chamber growth is necessary for oil production and that the rate of drainage is a function of the vertical height and (homogeneous) permeability of the steam chamber.

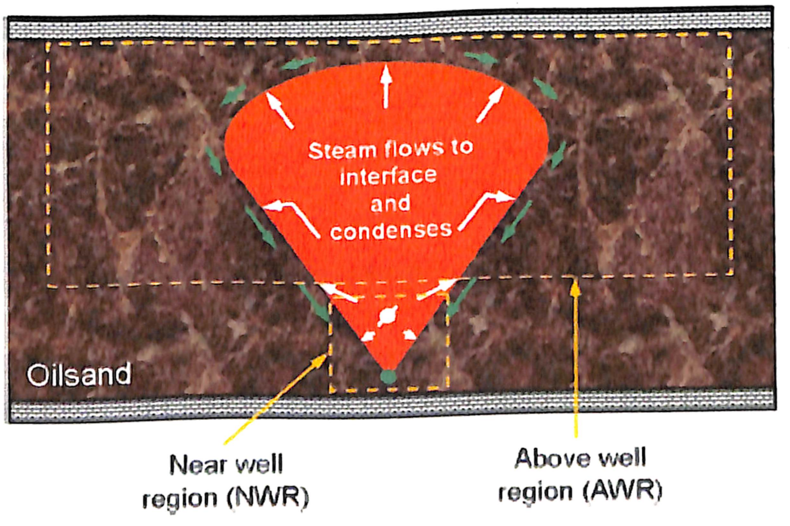


Figure 3: Schematic steam chamber growth in a SAGD process. Boxes drawn with

dashed lines indicate the near well region (NWR) and the above well region (AWR).

Consider a heterogeneous reservoir that contains randomly distributed shale barriers. The development of a steam chamber is affected to some extent and the ideal steam chamber shown in Figure 3 does not form. Because of the unique well arrangement and gravity driving mechanism, the steam chamber is expected to attain the inverse triangular shape during its development, although it will be distorted. The drainage path of hot oil and condensate is still along the slopes of the steam chamber. One analogy to such a drainage path is the fluid flow along the surface of a funnel.

The triangular shape and orientation of the steam chamber result in different Characteristic lengths. In the upper part of the chamber, the heated volume is large, and the steam flow inside and hot oil drainage around the chamber propagates in relatively long and wide paths. The flows in this region are of relatively long characteristic length, e.g., half of the formation height.

On the other hand, in the bottom of the steam chamber, all the flows are limited to the small region around the well.

Success of a SAGD process depends on the balance between a rising steam chamber and draining hot fluids. The effects of reservoir heterogeneity on steam rising and oil drainage are not the same throughout the formation because of the difference in the characteristics of the flows in different regions. This observation leads to the definition of two regions, the near well region (NWR) and the above well region (AWR). Each region is indicated in Figure above by dashed-lines. As demonstrated later, identification of the NWR and AWR makes it possible to decouple the complex effects of reservoir heterogeneities on the SAGD process.

2.1 Numerical Grid System

A SAGD project generally includes a series of parallel well pairs spreading through the formation, as shown schematically in Figure 4. The horizontal spacing between pairs varies from 75 m to 150 m in practice.

In this study, with the assumption of symmetry between well pairs, we consider a confined formation unit with one well pair in the center. A horizontal well spacing of 100 m is chosen accordingly. The well pair consists of two horizontal wells with lengths of 1,000 m. One well acts as a producer and the other as an injector. The production well is placed 1.5 m above the bottom of the pay zone and the injection well is drilled parallel to the producer with a vertical well spacing of 4 m. The vertical well spacing chosen here falls into the lower end of the practical range that ranges from 4 to 10 m.

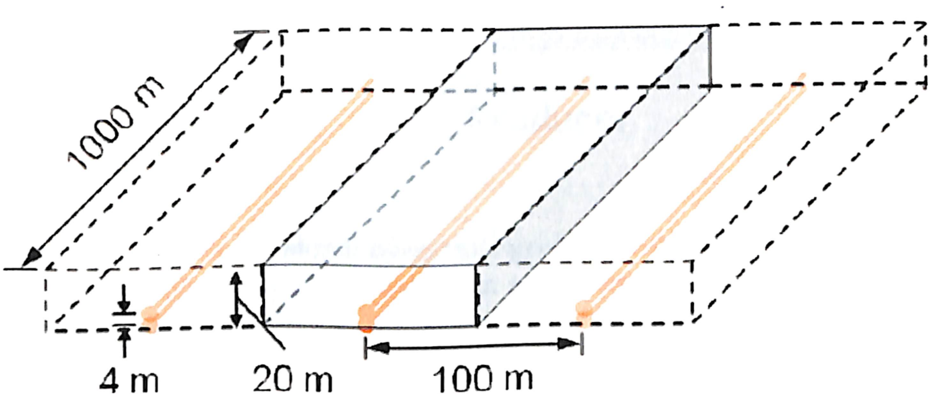
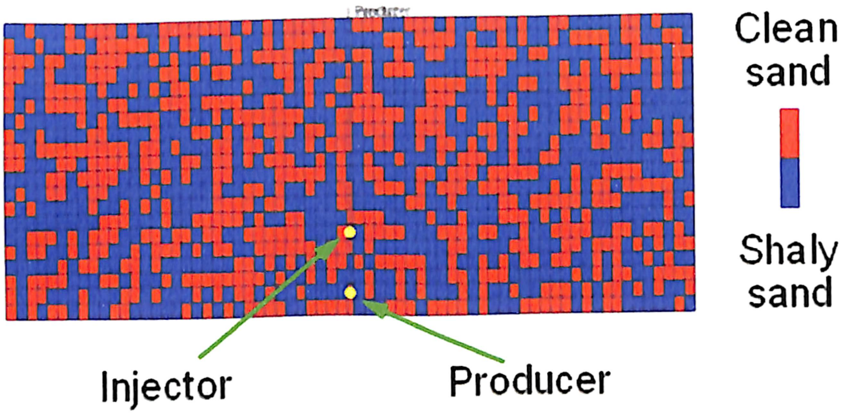


Figure 4: Schematic of parallel well pairs employed in practical SAGD projects.
The center gray block indicates a confined unit considered in our simulation model with assumption of symmetry between well pairs.

Figure 5 shows the two-dimensional grid system used for the reservoir simulation. The two-dimensional domain represents a vertical reservoir cross section perpendicular to the wells. This grid contains 67 grid blocks in the x-direction, and 20 grid blocks in the z-direction. The cells are 1.5 m wide and 1.0 m high, except for the center column in which the cells are 1.0 m × 1.0 m. The choice of the 1.0 m wide block in the center is simply to make the total width of the blocks add to 100 m. Our sensitivity analysis shows that such a choice of one smaller grid block in the center gives identical results to the case with the uniform grid system of the same block size. Also, this grid size in the vertical cross section was found to be sufficiently fine to resolve complex flows occurring in the vertical plane. The effects of grid size and the grid are examined in the Appendix A.

Figure 5: Two-dimensional numerical grids for SAGD simulation runs.

The blue and red grid blocks indicate shaly sand and clean sand, respectively. The distribution of the shaly sand and clean sand grid blocks is generated by SISIM with 30% shale content and 1.5 m shale correlation length.



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2.2 Shale Distribution

Due to the limitation of the experiments or simplification made in the numerical models, previous researchers studied reservoir heterogeneities by simply including a limited number of shale barriers at designed locations. Considering the intrinsic geological nature of shale observed in fields, one better representation of shale distribution is the stochastic model based on geostatistical methods.

In this work, reservoir heterogeneity is introduced by including randomly distributed, discontinuous, thin shale lenses. The shale is characterized by low vertical permeability, typically in the range of 10^{-9} to 10^{-6} D. For laterally-oriented thin shale lenses, it is acceptable to assume that the occurrence of shale in sand reduces dramatically the vertical permeability of the sand block, but has no effect on the horizontal permeability. Therefore, a reduction factor of 10^{-5} is applied to the vertical permeability of the shaly sand blocks in this study. As exact geological information of sand and shale sequences is not available to us, we model the distribution of shaly sands with a stochastic representation based on a geostatistical method, sequential indicator simulation (SISIM) (Goovaerts, 1997). In the geostatistical model, the probability of the shaly-sand occurrence (P_s) and correlation length of shale (L_s) are the two key parameters that determine the fraction of shaly sands and the continuity of shale in the distribution, respectively. These two characteristics of shale distribution, as demonstrated later, play important roles in the SAGD process. For each pair of P_s and L_s, SISIM generates a number of realizations, all honoring the predetermined data (e.g., hard data) and, thus all realizations are equally probable. Figure 5 shows one of the realizations obtained with $P_s = 30\%$ and $L_s = 1.5$ m.

2.3 Simulation Runs

The thermal and compositional simulator, STARS, developed by the Computer Modeling Group (CMG) was used for all simulation runs. The simulation runs are classified into two groups: (1) varying NWR and (2) varying AWR. For the baseline simulation runs, electrical preheating is first carried out at both well locations for 90 days to mobilize the oil around the wells and to establish hydraulic communication between them. Then, 95% quality steam at 3,000 kPa (i.e., 104 kPa greater than the initial pay zone pressure) is injected continuously at the upper well. The lower production well is operated using steam trap conditions to avoid excessive steam production. This steam trap control is achieved in the simulation by setting the production temperature 18 _F below the steam temperature to establish a definite liquid leg above the producer (Edmunds et al., 1994; Egermann et al., 2001). The simulation runs are terminated after 10 years of injection. The CPU times for two dimensional (67×20 grid blocks) simulations of a 10-year production on a Dell server (dual 2.8 GHz processors, 3.75 GB RAM) are 15 minutes approximately.

2.4 Results and Discussion

Next, steam chamber development and oil production are examined in the heterogeneous system. The role of shale barriers in the region immediately around the injection well is examined first.

2.4.1 Near Well Region — NWR

The extent of the NWR is chosen appropriately if a consistent SAGD performance is obtained for a number of equal-probability realizations (equally probable to occur) with a similar fraction of shaly sand (P_s) and shale continuity (L_s). These results are presented in two dimensions for ease of visualization and discussion.

Figure 6(a) illustrates three choices of NWR size, labeled small ($D_v \times 1.5D_v$), medium ($3D_v \times 1.5D_v$) and large ($6D_v \times 1.5D_v$) with respect to the vertical well spacing (D_v). For each case, three equal-probability realizations are generated. First, a random distribution of shaly sands is created and used as synthetic hard data. The fraction of shaly sands is 30% and shale correlation length is 1.5 m. The volume defined by a NWR size in this synthetic realization is then used as hard conditioning data to generate three realizations of shaly sand distribution. As a result, the three realizations in each case share the exact same configuration in the NWR, but have different AWR with the same fraction of shaly sand and shale continuity. Reservoir simulation runs were conducted with the three equal-probability realizations for each NWR size. Figure 6(b)–(d) compare SAGD performance in terms of oil production rate, oil recovery versus cumulative steam injection, and cumulative oil-steam ratio for the three sets of realizations. In all the figures, three types of curves (solid, dashed, and dotted) in the same color represent the three realizations for the same NWR size. As seen in the figures, the curves in blue corresponding to the case of small NWR size exhibit considerable variations between realizations. For instance, for the case of small NWR size, the startup time of oil production in Figure 6(b) varies from 300 days to 1,900 days, and the oil recovery after 10 years of operation differs from 40% to 70%. In contrast, the curves in green and red, for the medium and large NWR sizes, respectively, show consistent results between realizations. This comparison suggests that the medium size of the NWR ($2D_v$ by $1.5D_v$ where D_v is the vertical well spacing) is likely to be the appropriate definition of NWR size for this particular reservoir setting.

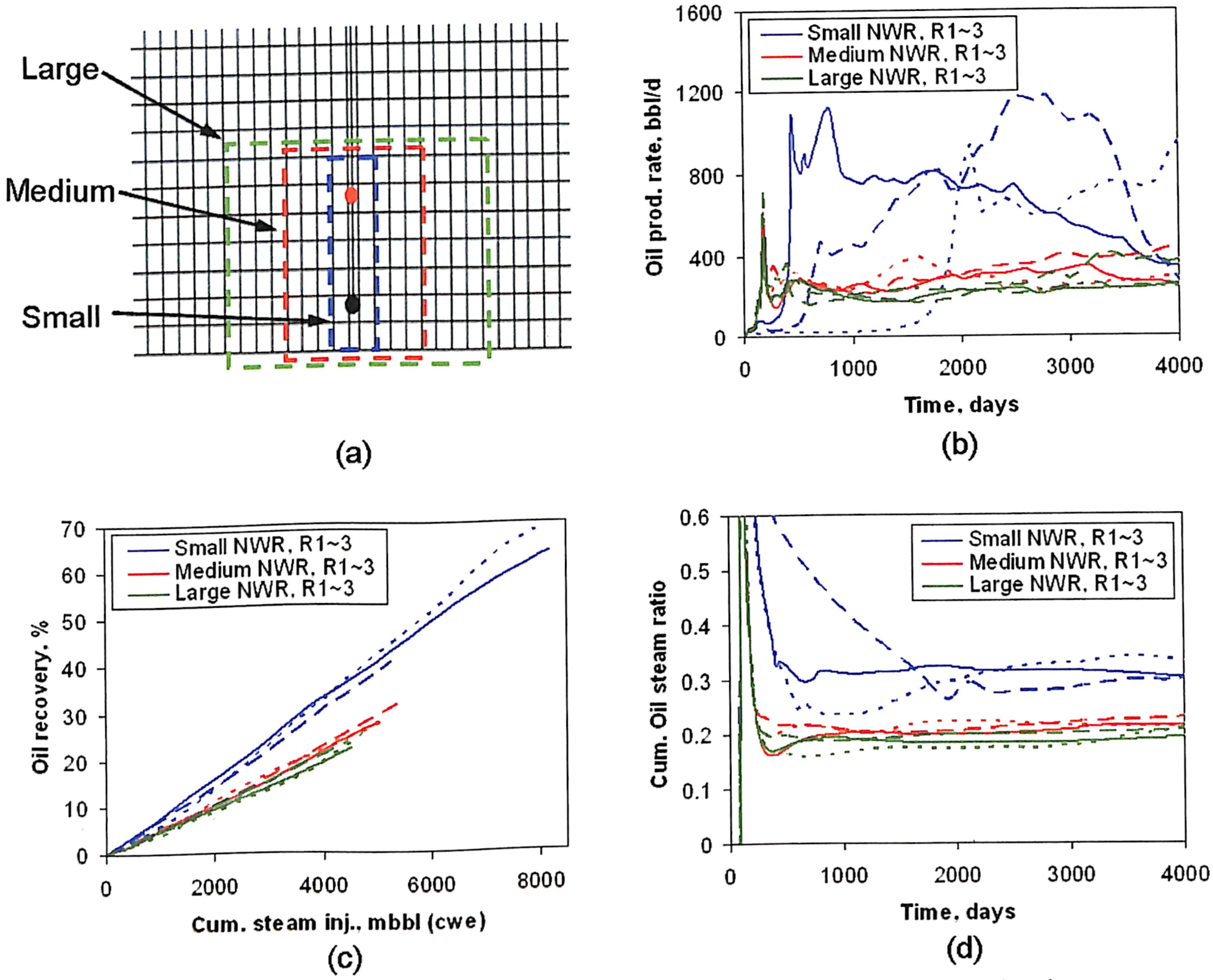


Figure 6: Comparison of NWR sizes: (a) definition of three sizes, (b) oil production rate, (c) oil recovery versus cumulative steam injection, and (d) cumulative oil-steam ratio.

This result is intuitive. The NWR affects the SAGD process mainly by influencing the drainage flow of hot fluids (water and oil) along the steam chamber boundary in the bottom portion of the chamber (Figure 3). Because the angle of the chamber wall with respect to the horizontal plane changes gradually as the steam chamber expands, it is reasonable to assume an average value of 45 _ for the qualitative analysis based on previous visualization of physical model experiments (Butler, 1998b) and simulation results. A rectangular region is determined with the angle to be $2D_v$ by $1D_v$ that covers fully the bottom part of steam chamber. This leads to a NWR size corresponding to the case of the medium NWR size in Figure 6(a). After determining the correct NWR size, we investigate the effect of the NWR on SAGD performance. Figure 7(a) shows two configurations of a medium-sized NWR. Two random realizations with 30% shale occurrence and correlation length of 1.5 m were used to select the NWR. The SAGD performance with three realizations conditioned to each fixed NWR are illustrated in Figure 7(b)–(d). Note that the three realizations share the same configuration in the NWR, but have different AWR with the same fraction of shaly sand and shale continuity. The result of the equivalent homogeneous model with a vertical permeability of 0.467 D calculated using a flow based up scaling method (Wen et al., 2003) is also included in Figure 7(b)–(d) as reference.

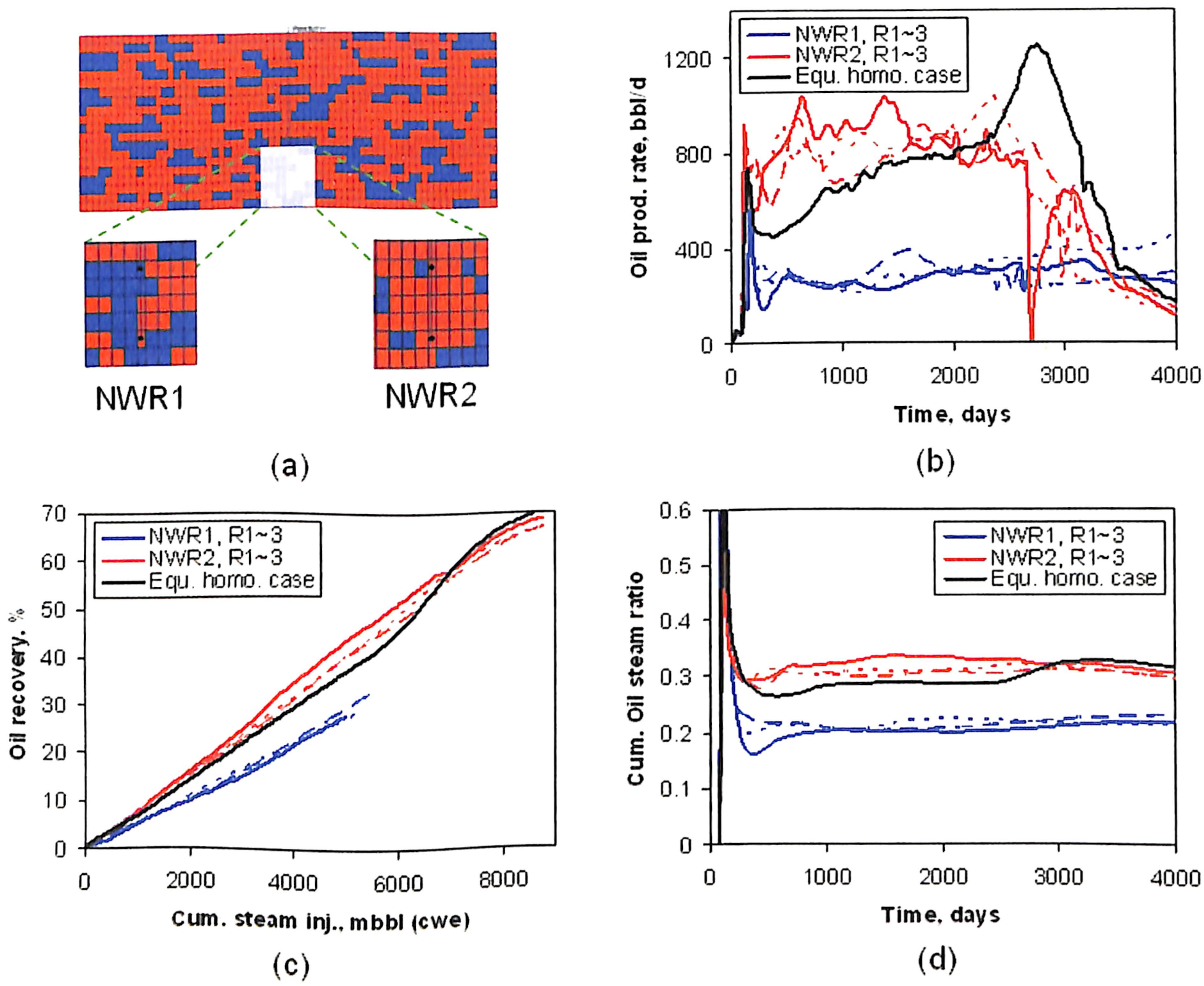


Figure 7: Comparison of SAGD performance between two shaly-sand distributions in the NWR: (a) NWR1 and NWR2, (b) oil production rate, (c) oil recovery versus cumulative steam injection, and (d) cumulative oil-steam ratio. The equivalent homogeneous case shown by the solid black line is included as a reference.

As expected, the curves in the same color that represent the cases with the same NWR collapse together with acceptable variance. This confirms that the determined NWR size is appropriate. Secondly, two sets of curves, in red and blue, as illustrated in Figure 7(b)–(d), reveal dramatic differences in SAGD performance between realizations that have different shaly-sand configurations in the NWR. For the case of NWR1, all three realizations yield an average oil production rate of about 300 bbl/d. This rate is less than half the oil production rate of NWR2, which is 800 bbl/d. Similar results are observed in the comparisons of oil recovery and cumulative oil steam ratio.

This large discrepancy is mainly attributed to the manner in which the permeability distribution in the NWR affects the steam chamber development. Effectively removing heated oil and condensate from the reservoir is necessary for continuous steam injection and thus successful steam chamber expansion. Hot fluids must pass through the NWR before being produced. Therefore, a NWR with substantial vertical and horizontal connectivity facilitates fluid drainage thereby aiding steam chamber development. If the NWR contains shale barriers that impede vertical flow, the drainage path of hot oil may be blocked in the NWR. Moreover, because of the relatively short characteristic length of flows in the NWR, the drainage flow is sensitive to the distribution of shale barriers in the NWR, especially when the shale continuity is increased. The above analysis is easily verified by visual comparison of NWR1 and NWR2 in Figure 7(a). The comparison of SAGD performance between the cases of NWR1 and NWR2 suggests that in practice horizontal well pairs should be placed in the high quality region (less shale) of the formation to optimize SAGD performance.

2.4.2 Above Well Region — AWR

Two sets of simulation runs were conducted to investigate the effect of the shale Percentage and shale continuity in the AWR. In the first set, the fraction of shaly Sands is fixed at 30%, and the shale correlation length is varied as 1.5 m, to 6 m,12 m, and 24 m. In the second set, the shale correlation length is fixed at 6 m, and the fraction of shaly sands is changed from 10% to 30% and 50%. All permeability realizations are conditioned to the same predetermined NWR data (NWR2 shown in Figure above).

Figure 8 compares the effect of shale continuity in the AWR on SAGD performance. Again, for reference purpose, the equivalent homogeneous cases are presented by dashed lines in Figure 8. For each case of the shale correlation length, reservoir simulation runs were conducted with three realizations. As their responses are consistent, only one is plotted in the figure. The figure shows that oil production is strongly correlated to the shale continuity. The oil production rate curve for the more continuous shale, for example, is below that for the shale with shorter correlation length.

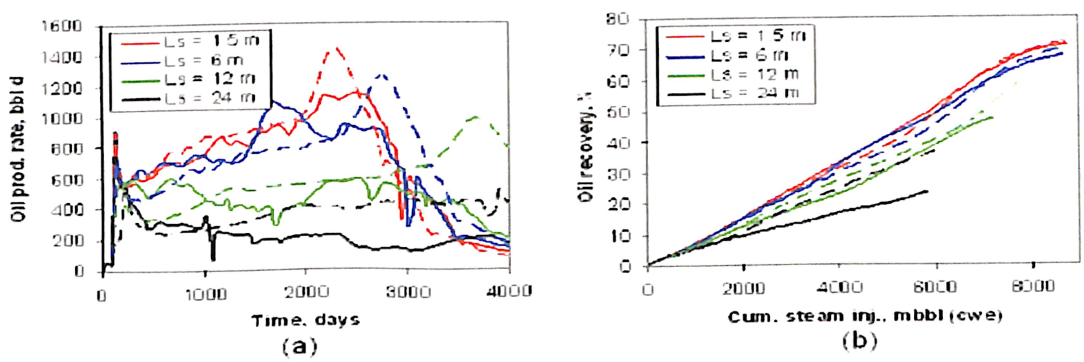


Figure 8: Effect of correlation length of shaly-sand in AWR on SAGD performance:
(a) Oil production rate and (b) oil recovery versus cumulative steam injection. The dashed lines in the figures present the results of the equivalent homogeneous cases whose permeabilities are obtained from the corresponding cases (in the same color) using a flow-based up scaling method (Wen et al., 2003). The equivalent vertical permeabilities are 0.615, 0.467, 0.310, and 0.203 D as the shale length increases

As the shale becomes more continuous, from 1.5 m to 24 m, the oil recovery factor decreases from 70% to 23% after 10 years of injection, and the cumulative oil steam ratio reduces from 0.3 to 0.15. Notice that this decreasing trend is not uniform. For changes in shale continuity from 1.5 m to 6 m, the resulting difference in SAGD performance is not obvious, but when the shale correlation length is significant, they cause dramatic reduction in oil production. This is because the steam chamber expansion mainly occurs in the AWR. The flows associated with the steam chamber expansion are of relatively long characteristic flow length depending on the steam chamber height. As a result, the horizontal barrier formed by shale can only affect the steam chamber development when it is greater than about 12 m. Otherwise; steam easily bypasses the discontinuous shale and extends the chamber further into the cold zones.

These observations are corroborated by the temperature profiles. The critical shale length that effectively limits the steam chamber growth is observed to be about half of the formation thickness. Such results confirm our analysis of the flow characteristic length in the AWR. When the fraction of shaly sand increases, we observe a similar reduction trend in

SAGD performance. as presented in Figure 9. Note that the dashed lines in Figure 9 represent the results of the equivalent homogeneous cases. The case with 10% shale gives the greatest oil production rate as well as the best oil recovery factor Note that there is a sharp fluctuation in the oil production rate at 3,000 days for the 10% shale case. This is likely attributed to the steam trap control that triggers an increase in the producer BHP at 3.000 days to avoid steam breakthrough. There is a small reduction in oil production when the shale percentage is increased by 20%, whereas another 20% increase in shale percentage results in a substantial reduction in oil production, i.e., approximately 60% decrease in both the average oil production rate and oil recovery factor. As the shale percentage increases, the shaly sand blocks form a more continuous barrier to the vertical flow that, in turn, limits the development of the steam chamber.

2.5 Concluding Remarks

The complex effect of reservoir heterogeneity on the SAGD process is decoupled by identifying two flow regions: the near well region (NWR) and the above well region (AWR). The drainage and flow of hot fluids within the NWR are of short characteristic length and found to be very sensitive to the presence and distribution of shale. Based on this observation, we suggest placing horizontal well pairs in the high quality region of the formation to optimize SAGD performance. On the other hand, the AWR affects the (vertical and horizontal) expansion of the steam chamber that is of characteristic flow length on the order of half of the formation height. SAGD performance is affected adversely only when the AWR contains long, continuous shale or a high fraction of shale.

It is also shown clearly in our simulation results that SAGD operations yield low or moderate oil production rate and recovery in reservoirs with poor vertical communication due to the presence of a high percentage of shale or continuous shales. Applications of conventional SAGD to such reservoirs that are quite common in reality would be problematic from the economic-perspective.

3. Basics of Hydraulic Fracturing

Hydraulic fracturing is the process by which we establish a conductive path from the reservoir to the well. Hydraulic fracturing mainly depends on the objectives, the reservoir and the well.

3.1 The Basic Process

The basic process of hydraulic fracturing involves pumping the fluid into a permeable formation, generating a pressure differential proportional to the permeability of the formation, Kf. As the rate increases, this pressure differential between the well and the original reservoir pressure also increases. An additional stress is caused by this pressure difference around the well. Over time, as the rate increases, this pressure difference will emphasize the limits of the force needed to break the rock away, and a fracture is formed. At this point, if the pumps are switched off or pressure is purged, the fracture is closed again. Over time, depending on the hardness of the rock and the magnitude of the force acting to close the fracture, it is as if the rock had never been broken. Fracture does not increase production by itself.

However, if a proppant is pumped in the fracture and release pressure, the fracture will stay open a little, provided that the proppant is stronger than forces trying to close the fracture. If this proppant also has significant porosity, then it is an appropriate situation of creating a path of increased permeability from the reservoir to the well. If treatment is designed properly, this will produce an increased production.

In general, the fracturing process requires a high viscosity fluid to be pumped into the well at high speed and pressure, although this is not always the case (see the skin of fracturing derivation below) so the process usually involves large trucks or skids with large diesel engines and massive pumps. A typical pump is of nominal 700-2700 hydraulic horsepower (HHP) - to put this in perspective; the average car motor (outside North America that is) has a maximum power of 80 to 100 HP.

For creating a fracture a liquid phase is usually pumped first. This is followed by several stages of proppant-laden slurry, which actually caries proppant in the fracture. Finally, the whole treatment is shifted to the perforations. These stages are performed consecutively, without a pause. Once the shift is over, the pumps are turned off and the fracture is allowed to close on the proppant. Fracture Engineer can change the size of the track, sizes proppant stage, the number of stages proppant, proppant concentration stages, the total pump rate and type of fluid to produce fracture characteristics required. Typically, treatment will look like Figure 9:

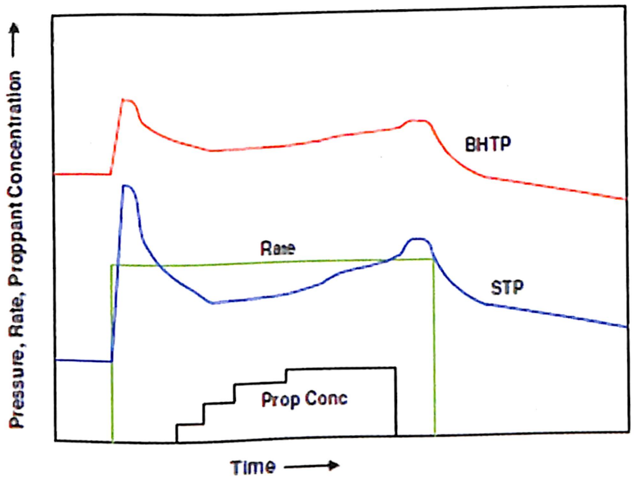


Figure 9: Typical hydraulic fracture treatment

3.2 Pressure

Everyone Know what is pressure. If someone is asked to define the pressure, they usually going to say "force divided by area "or somewhat similar. This is not what the pressure is.

The simple fact is that the pressure is the stored energy used to perform work on the formation during the fracture process. Everything we do in the fracture can be considered in terms of energy. Starting from pumping a fluid in a fracture that begin with chemical energy - in the form of diesel fuel. This energy is then converted into mechanical energy by diesel engine. The high pressure pump then transfers this mechanical energy into pressure fracturing fluid. As the fluid moves into the formation, the pressure becomes training stress, which is another form of stored energy, so that the walls of the fracture are pushed back, creating fracture width and forcing the break to spread.

Work is defined as the rate of use of energy - in the SI system; a watt is defined as one joule per second.

The pressure and stress is necessarily the same thing. The only difference is that stresses act in sound and pressure in liquids and gases act. Since liquids and gases easily deformed any force used, the pressures acts equally in all directions. Stresses, however. tend to act along the flat, so that a solid will always have a stress level in the direction where emphasizes a maximum, and a plane perpendicular to this, where tensions are at a minimum. In Split, we refer to several different pressures. These names are few to be remembered where and when we are measuring (or calculating) the pressure;

STP – It is also known as the wellhead pressure, injection pressure, pressure pipe (in case of pumping down the tube), PSTP, Pwellhead, Ptubing and so on. The name speaks for itself as it is the pressure that the pumps have to act against the surface.

Hydrostatic pressure It is also called HP, PH, HH and Phydro. This is the pressure because of the weight of the liquid column in the well downhole. This pressure is a function of the density of the fluid and the vertical depth:

$$HH=0.433gTVD$$

where HH is the hydrostatic pressure in psi, g is the specific gravity and TVD is the true vertical depth on which the pressure is acting. This seems to be easy to calculate, but can become very complicated in a dynamic system in a deviated well with fluids of various different densities made in the well - which is the usual situation for a fracturing job.

Pipe Frictional pressure It is simply called the friction pressure, or Pfrict. We can define it as the pressure caused by resistance faced by the fluid flowing in the pipe. Frictional pressure decreases with increasing tube diameter and increases as the rate increases.

Bottom hole pressure treatment It is also known as BHTP. This is the pressure inside the well for the formation being treated. In general, it is calculated in the center of the interval drilled. In this point the liquid has passed through the perforations or fractures. This pressure is usually calculated: -

$$BHTP = STP + HH - P_{frict}$$

Perforation friction pressure – It is also known as drilling or Pperf friction. This is the friction pressure experienced by the fluid while passing through the perforations: -

$$Pperf = SG\ 2.93\ (q / n)\ 2\ d4$$

Where Pperf is in psi, SG is specific gravity, q is the rate in bpm, d is the drilling diameter in inches and n is the number of perforations.

Near wellbore friction pressure – It is also called near wellbore friction or Pnwb. It is the sum of drilling friction and pressure losses caused by the tortuosity.

Closing pressure – It is also called Pclosure (Pc). This is the force acting to close the fracture. If the pressure is below closure pressure, fracture closes, and at the pressure above this the fracture remains open. This value is important in the fracture and is usually determined from a Mini fractures, to make a careful examination of the reduced pressure after pumps are closed.

Extension pressure – It is also called Pext. Extension pressure is necessary for the extension of fractures. It is usually, 100 to 200 psi greater than the closing pressure and this pressure difference represents the energy required for the propagation of a fracture, compared to just keep it open (i.e. Pclosure). In hard formations, extension fracture pressure is almost equal to the closing pressure. In softer formations, where significant amounts of energy can be absorbed by plastic deformation at the tip of the fracture, extension pressure can be significantly higher than Pclosure. The extension fracture pressure is obtained from a step rate test.

Net pressure – It is also called Pnet. This is a fundamental value used in the fracture and the analysis of this variable forms an entire branch of the theory of fracture itself. Pnet is the difference between fluid pressure in the fracture and closing pressure, such as: -

Pnet=BHTP-Pnwb-Pclosure

STP = HH - Pfrcit - Pnwb - Pclosure

Instantaneous close pressure - This is the pressure that can be determined, either surface or bottom hole, obtained immediately after the bombs go off down in the beginning of a decline in pressure. If measured in the bottom hole it should be equal to the BHTP. One method to determine it is to compare the CIMI and a Mini fracture BHTP (provided that BHTP is reliable).

3.3 Fluid Leak off

Hydraulic fracture treatments were pumped into permeable formations - it makes little sense carry out the training process with zero permeability. This means that as the fracturing fluid is pumped to a formation, a certain proportion of this fluid lost in the formation as leak off fluid.

The leak off coefficient is a function of (kf) formation permeability, the fracture area A, the pressure difference between the fracturing fluid and the formation, compressibility, viscosity and fluid characteristics. Often, this ratio is kept constant throughout the treatment, which means that the fluid loss rate varies with time and fracture area only, and does not depend upon the difference in pressure or flow rate. The effect of formation permeability and fluid characteristics are often combined into a single leak off coefficient of different denominations, Ct, Cl or Ceff. We will use Ceff.

VL = Ceff* p* A* t

Where t is the time for which the fracture has been opened. Unit of Ceff is m / min and a half, so if the area in square feet, the volume leak off is in cubic feet. Remember area A is the fracture surface of a whole, including both sides of the two wings of fracture. A geometry model of the fracture should be used to determine the value of A. In a multilayer deposit, with different values of Ceff for each zone, the total leak off is the sum of the leak off for each zone.

A more accurate method to calculate fluid loss is to use a dynamic leak off model, in which variations in differential pressure and fluid composition are taken into account. In dynamic leak off the total energy is generally assumed to have three components: the controlled viscosity coefficient Cv or CI, controlled compressibility Cc coefficient or CII and the construction of walls Cw or CIII ratio.

The controlled viscosity coefficient is the effect of filtrate split movement in the Darcy formation linear flow conditions, defined as: -

$$C_I = 0.0469\sqrt{\frac{k_f \phi \Delta P}{2\mu_f}}$$

Where kf is the permeability of the formation to the filtrate fraction, Φ is the formation porosity and μ_f is the fraction of filtrate viscosity in cp.

The compressibility coefficient is due to the formation compression, and the volume allowed in the filtrate fraction can be moved. Is defined in field units, such as: -

$$C_{II} = 0.0374\,\Delta P\sqrt{\frac{k_r c_f \phi}{\mu_r}}$$

Wherein kr is the formation permeability to the fluid reservoir, cf is the compressibility and μ_r is the viscosity of the liquid in the tank cp.

The construction of walls coefficient is usually estimated experimentally using a standard fluid loss test. We obtain this by plotting filtrate volume against the square root of time, to give a slope m. The wall-building ratio is defined as (in units of field): -

$$C_{III} = \frac{0.0164\,m}{A_f}$$

Where Af is the area of the filter cake in the cell fluid loss. In general, the fracture and modern simulator provide with the wide range of coefficients of building walls of fracturing fluids, so that all engineer has to do is select the type of fluid.

The three components can then be combined to produce Ceff as follows:-

$$C_{eff} = \frac{2\, C_i C_{ii} C_{iii}}{1 + \sqrt{(C_i C_{ii})^2 + (4\, C_{ii}^2\, (C_i^2 + C_{iii}^2))}}$$

This is for dynamic fluid leak off. The components can be arranged in a different form for Harmonic fluid leak off:-

$$C_{eff} = \frac{(C_i C_{ii} C_{iii})}{(C_i C_{ii} + C_{ii} C_{iii} + C_i C_{iii})}$$

This process of deducing the theoretical rate leak off seems to be quite intimidating, and in practice only used in simulation of fracture. During the analysis of Minifrac, the permeability values and building walls coefficient are varied to produce the required leak off. In general, the dynamic model is better than the harmonic, but in real circumstances there is not much difference between the two. This is especially true for a no fluid-wall construction, or gas deposits.

3.4 Near Well bore Damage and Skin Factor

Darcy equation for radial flow defines the rate at which oil is produced from the reservoir in the well under steady flow conditions. In the field units of an oil well, The equation is as follows: -

$$q = \frac{0.00708\, k\, h\, \Delta P}{\mu \ln (r_e/r_w)}$$

Where q is the flow from the well in barrels / day. We can see that the radius of the well, rw has a great impact on the flow rate. This is easy to visualize, because the closer the fluid reaches the routes flow are more congested and the liquid moves faster. Therefore, the final few inches down the shaft are the most critical part of the reservoir. Unfortunately, this part of the reserve is also more susceptible to damage. This damage can come from a variety of sources, but more often comes from the well drilling process first.

What this results in, is a region around the wellbore of reduced permeability, as illustrated in Figure 10.

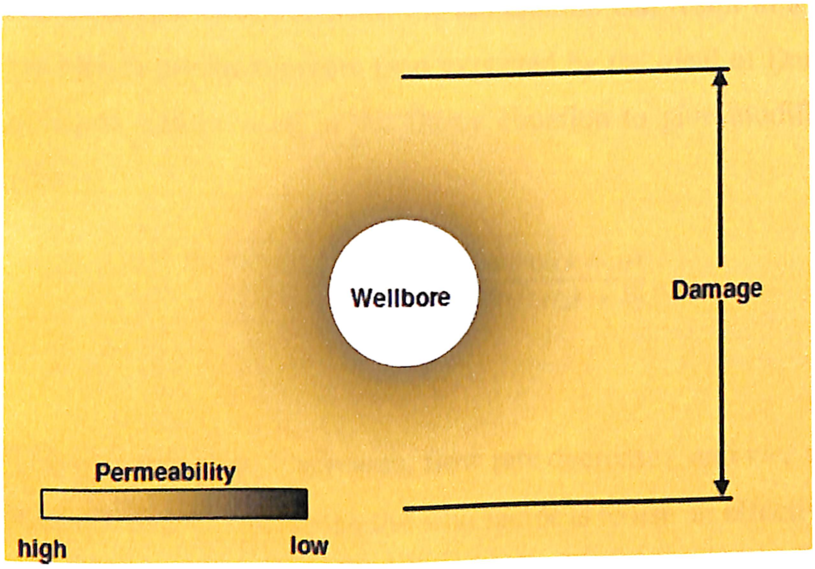


Figure 10: Illustration of the reduction in permeability around the wellbore

This reduction in permeability around the wellbore is generally referred to as the skin, which was streamlined for the first time by Van Everdingen and Hurst (1949). The skin factor, S is a variable used to describe the difference between the ideal output and real output through the damaged area. Generally, the skin is determined using a pressure buildup test. The API defined the factor of the skin of an oil well in the following way: -

$$S = 1.151\left(\frac{P_{1hr} - P_{wf}}{m} - \log_{10}\frac{k}{\phi\mu c r_w^2} + 3.23\right)$$

Where Pwf is stabilized bottom hole flow pressure (PSI), P1hr is the bottom hole pressure after an hour of static buildup pressure (Psi), k is the permeability of the formation, m is the slope of the graph of P against log 10 $[(t + \Delta t)/\Delta t]$ (in psi per log10 cycle), f is the porosity (fraction), m is fluid viscosity (cp), c is the average deposit compressibility (psi-1) and rw is the radius of well (in feet). To help matters, m can be found from the following (in field units):-

$$m = \frac{162.6\, q \mu}{k h}$$

Note that both q and m are bottom hole conditions. A completely free deposit has a skin factor of zero. Damaged dams have skin varying from 0 to 50 or even higher. Under certain circumstances, the stimulation can result in a negative skin which means that the well is producing more than expected by the ideal of Darcy flow. Once the skin factor is obtained, can be used in the Darcy equation to give modification of a flow tank damaged skin: -

$$q = \frac{0.00708\, k\, h\, \Delta P}{\mu\, [\ln (r_e/r_w) + S]}\, .$$

This means that as S increases, flow rate decreases, and *vice versa.*

Another way of employing the skin factor is to use an effective wellbore radius, as given in Equation:

$$r_w' = r_w e^{-S}.$$

This means that in a damaged wellbore, the well is behaving as if it had a smaller wellbore radius, where as a stimulated reservoir behaves as if it had a larger wellbore radius.

3.5 Fluid Systems

The fracturing fluid is a vital part of fracturing process. It is used to initiate the fracture, carry the proppant into the fracture, and keep the proppant in suspension until the fracture closes. In a more basic level, the fluid system is the vehicle allowing the transfer of mechanical energy (in pumps fractures) in a study performed in training. To be called an efficient fluid it must have a combination of following properties.

i) Low cost.

ii) The ease of use.

iii) Low pressure pipe friction.

iv) The high viscosity in the fracture, to suspend the proppant.

v) Low viscosity. after treatment, to allow easy retrieval.

vi) Support for training, reservoir fluid and proppant.

vii) The safety of use.

viii) Eco-friendly.

Some of these properties are not easy to combine in the same fluid. In general, the process the selection of a fracturing fluid is a compromise. It is for the engineers to decide which properties most important and what properties may be sacrificed. To make this election easier, there is a number of fracturing fluid systems.

3.5.1 Energized Fracturing Fluids

Liquids under tension consist of a liquid phase - usually a water-based gel or crosslinked linear - and a gaseous phase, which is typically N2, CO2, or a combination of both. Such treatments involve large amounts of equipment and personnel. Consequently, relative expensive. These treatments also refer to foam tuxedos, as the foam is what is generally reach training. Fluid foam has several unique properties that make them advantageous under certain circumstances:

i) The viscosity and proppant transport. Stable foams have a relatively high viscosity and make excellent transport fluid and proppant suspension.

ii) Leakoff foams have very good properties. This is due to the effects of multiphase flow as the foam is moved through the formation porosity

.

iii) Because the foams are typically only 30-40% of fluid, which are more compatible with water sensitive formations that fracture systems that are 100% liquid.

iv) The additional energy stored in the liquid, along with the low hydrostatic pressure foam, makes fluid recovery relatively easy.

3.5.2 Foam Quality

The quality of the foam often expressed as a percentage or simply as a quality (i.e., "70 qualities" or even "70Q") is the percentage of foam or liquid gas in the fracturing fluid. To design a foam treatment, an engineer must have a reasonable idea that the opening provided treat pressure and temperature, as volume occupied by the gas phase may vary depending on these two (although the temperature is much less important than the pressure). As illustrated in Figure 11 the foam viscosity (and therefore the ability to transport proppant) is strongly influenced by the quality. If bottom hole pressure is significantly lower than the expected value, the quality of the foam will be too high, and the gas phase will be expanded to make a mist instead of foam.

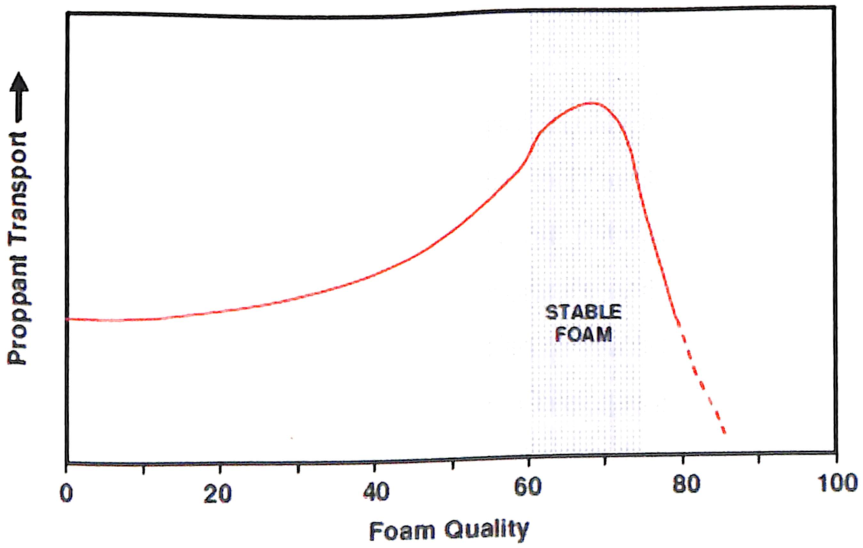


Figure 11: Proppant transport as a function of foam quality.

3.5.3 Foam Stability

The stability of the foam is its ability to remain as the foam phase rather than separating into two or even three phases. Ideally, the liquid foam must remain sufficient for the liquid recovered through the roof after treatment. Obviously, temperature and fluid contamination are the factors responsible for reducing foam stability. There are three main methods to maximize the stability of the foam: -

i) Mixing the liquid and gas phases in high shear, such as a foam generator, or mixed phases passing through a high-cutting device, such as strangulation. More the court that the experiences of the foam, the more stable it becomes. High Court acts reduce the average size of gas bubbles, which in turn makes it harder for later out separately.

ii) Crosslinking of fracturing fluid after the foam has been formed- Using a delay crosslinking, the onset of crosslinking can be programmed to take place after the foam has been generated, so that gas bubbles are, literally, cross-linked in position.

iii) Blowing agents- These surfactants act to increase the surface tension of a material so that gas bubbles are much more stable. Often a combination of the above methods is used.

3.5.4 Foam Viscosity

Viscosity, proppant transport characteristics, leakoff liquid and foam stability are influenced by the nature of the foam itself such as the viscosity of the liquid phase, the average gas bubble size, the quality of the foam and surface tension properties of the liquid phase. All these are affected by temperature and two of them are significantly affected by pressure. This means that the calculation of viscosity and therefore the pressure and friction leakoff liquid , Foam is very difficult. Consequently, estimates for the bottom hole pressure management foam tuxedos are unreliable and should not be used for analysis, unless there is absolutely no alternative. The results of this analysis should be considered as conjectures only.

4. Foams in Oil Industry

4.1 Introduction

The continued use of gas injection to improve oil recovery and the prospects of its increasing use world wide helps to drive to improve sweep efficiency by gas. Injection work is being done to improve understanding and control agent's economy of mobility.

No reservoir is completely homogeneous. The porous medium in the reservoir is characterized by the distribution of pore size and pore throats, leading to non-uniform displacement. Darcy law says that the mobility of a single phase in porous media is inversely proportional to its viscosity. The gases used in gas flooding (such as CO2, hydrocarbons, N2, etc.) are usually less viscous (more than an order of magnitude less) and less dense than water and crude oil, resulting in channeling gas through the high permeability zones and the severity of the first order. Because of this reason, gas flooding usually has low volumetric sweep efficiency, especially in an immiscible displacement phase shift of low density. A need for mobility control in gas flooding has led to the use of foam for improved scanning and profile modification.

Several oil recovery processes are known and used in industry, such as water injection, fireflood, steam flooding, and the unit of gas, miscible flooding and polymer flooding. As mentioned above, the process of the foam is also known and used. The foam is used to improve the efficiency by which the liquid spreads through the movement of the shell and the contacts and the oil is recovered. The utility of the invention lies in improving sweep efficiency when it is used in improved oil recovery processes. sweep efficiency is broadly defined as the volume of training scanning / total volume.

The foam is dispersion colloid in which a gas is dispersed in a continuous liquid phase. Surfactants are added to the solution to stabilize the foam to reduce the interfacial tension. Many studies have shown that surfactant stabilized foam could dramatically reduce gas mobility in porous media, thus improving volumetric sweep efficiency and oil recovery.

There is considerable interest in the application of foams in enhanced oil recovery processes involving the displacement of miscible or immiscible gases (CO_2, hydrocarbon gases, etc.) From foam reservoir which can provide a means to counter the moving agent naturally high mobility and low density, which may reduce the finger (pipeline), reversing gravity. The foams can also be applied to short and reduce gas coning. Gases such as steam, carbon dioxide (CO_2) and hydrocarbon gases are injected into oil reserves to increase oil recovery. These gases have less density and viscosity than oil in its attempt to move, so it tend to finger through or migrating to the top of the tank, leaving most of the oil behind.

4.2 Use of Foam:

The foam is injected into geological formations for the diversion of gas in Enhanced Oil Recovery (IOR), acid diversion in matrix and acid stimulation and environmental rehabilitation. Foam can be injected or alternating slugs of gas and liquid. In remediation IOR and the environment, it is often useful for injecting gas and surfactant solution in alternating slugs, called surfactant-alternating gas injection or SAG. SAG injection has several advantages over the co-continuous injection of gas and liquid. As part of the Enhanced Oil Recovery (IOR), foams can be used as follows (details can be found later, when cases are treated in the field):

1) The foam used as a stimulant to increase gas production
2) The foam used to reduce the water cut.
3) The foam used to reduce gas mobility.
4) Gas shut off with foam.

4.3 Reason for using Foam:

water-soluble polymers of high molecular weight, such as partially hydrolyzed polyacrylamides are the usual method which provide mobility management and thereby improve sweep efficiency in the processes of surfactant and alkaline / surfactant enhanced oil recovery. Foam offers the possibility of further improvements in sweep efficiency, especially in heterogeneous reservoirs, because the mobility of the foam is lower (apparent viscosity is higher) in layers of high permeability than in low permeability. While additional surfactant is needed to generate the foam, its amount and the cost are less than the cost of polymer and that half or more of the liquid gas is injected in the case of the foam. The residual oil recovery is excellent in both cases for the mixture of surfactant used. Apparent viscosity of foam is about a factor of five larger in the sand pack with the highest permeability, confirming the ability of foam to provide a more uniform sweep polymer.

The use of foam to improve sweep efficiency of the fluid involves the use of two properties of the foam. The first is the high flow resistance that is associated with the foam. The second property is the large surface area of gas-liquid. Therefore, the relatively small amounts of an aqueous solution of a foaming agent are necessary to use relatively large amounts of dense gas or liquid. The gas is dispersed in the liquid, creating a large interfacial area and a large amount of foam, which increases the resistance to flow. If this resistance to flow is in those regions of the reservoir, where the resistance is lower, then the fluid moves is forced to flow through the regions of greatest resistance, sweeping large parts of the reserve and recovery of large quantities of oil . Therefore, the use of foam improves the sweep efficiency.

The blowing agent is selected for a brine tank mostly because the characteristics of the foam production are affected by the nature of the reservoir rock, such as carbonate or sandstone reservoir temperature and pressure conditions, and composition of reservoir fluids, such as salinity, divalent ion concentration, pH, etc. The water used in the aqueous solution may be fresh water, salt produced reservoir, gas or water. Under typical reservoir conditions of temperature and pressure, the foam is composed of thin films of a liquid that is separated by the fluid it displaces, which is a dense gas or liquid. A preferred method for generating foam in-situ in the reservoir comprises injecting the aqueous slug before the fluid it displaces. The water slug can also be injected between two slugs of fluid it displaces. The size or slug volume of water varies between 1 and 90% (volume) the volume of the pores. The size of the bullet that moves the liquid is dictated by the size of the reservoir, and separation reservoir fluid saturation, and Tank rock properties. The relationship between the sizes of the fluid that displaces the water slug size can vary between about 100:1 and 1:01. Fluid can move one or a mixture of carbon dioxide after the nitrogen, air, methane, ethane, propane, butane, hydrogen combustion or exhaust gases or stream.

4.4 Elaboration on foam quality and viscosity

Foams, which are mixtures of a gas phase, liquid phase and a surfactant, meet the basic requirements for good fracturing fluid, however, the foam fluid properties are derived from a different structure from that gelled in the water.

The foam quality is defined as the volume of gas divided by the total volume of the foam. In general, the higher the foam quality, higher the viscosity. The high apparent viscosity of the foam due to the interfacial structure of the foam bubbles. In very low quality foams, for example, Below 50 quality, spherical gas bubbles are free to move with little bubbles restrictions adjacent. In foams above approximately 50 qualities, bubbles are touching each other and allow less freedom of movement within the total fluid. In high quality foams, i.e. over 75 qualities, the bubbles pile up and are no longer spherical. In the fluid motion are very restricted apparent results, therefore, high viscosity.

In static foam, liquid, drain the liquid and foam at the top are effectively increasing the quality. As the quality of the foam increases, viscosity also increases as the bubbles that distort a spherical shape and the film adopts a flat configuration. Sand particles held in place by the foam structure and are not easily solved through it. When the quality of static foam increases, the structure becomes rigid, giving further support to the sand.

Foams in the range from 65 to 80 quality are commonly used in the fracture of the foam. So it is easy to transport proppant through the foam and then supported once the fracture has been created. As a result, the proppant is more evenly distributed within the fracture rather than simply allowing it to settle to the bottom of the fracture. Foam has been shown to have excellent fluid loss for the formation of low permeability.

Clay formations that are sensitive to water can be extended to reduce permeability or migrate to block the flow channels of contact with water. Foam helps minimize water damage to the formation by the low total water content of the fluid. Additional clay protection can be achieved through the use of inorganic salts and polymer clay stabilizers.

A major advantage of a fluid foam fracture fluid recovery efficiency. When released the wellhead pressure, low hydrostatic head in the well has a lower resistance to the production of foam liquid fraction for a gelled water flow. Nature compressible foam also helps to bring the liquid back due to the expansion of gas in his return to pot. This expansion is more favorable to gas wells with low formation pressure. Cleaning of a foam fracture treatment is usually carried out within two days, while a gelled water fracturing treatment may require several days.

A particularly preferred process to carry out this invention comprises the following steps:

1) A moving fluid, such as carbon dioxide, is introduced into the formation of an injection well. As the injection of fluid is continuous, fluid flows through the regions of the flow resistance, contact with the oil and displace it. Therefore, oil recovery is achieved in the shortest time.

2) When the gas produced (liquid moves) / oil ratio approaches levels that are too high to make the process economical, an aqueous slug comprising the mixed surfactant system, such as 0.5 wt. % of each surfactant and a foaming agent is injected such as foam lignosulfonate. This new slug flow preferentially through regions of the reservoir where the flow resistance is lower. The water slug size is 5% of the total pore volume.

3) Injection of the fluid it displaces is resumed. Initially, the fluid flow travels through parts of the shell where the flow resistance is lower, or regions of high permeability. There the fluid displacement is spread along the water slug and foaming. As more foam is generated, the resistance to flow increases in these regions of high permeability. Consequently, the liquid move is forced to flow through low permeability regions and move additional quantities of oil. During the execution of this step, the size of the perforation displacement depends on the fluid flow that moves itself, as well as the size of the reserve, well spaced, reservoir fluid saturations and properties, and deposition and properties of rocks.

4) The second and third steps are repeated as many times as necessary until the economics of the process become unfavorable.

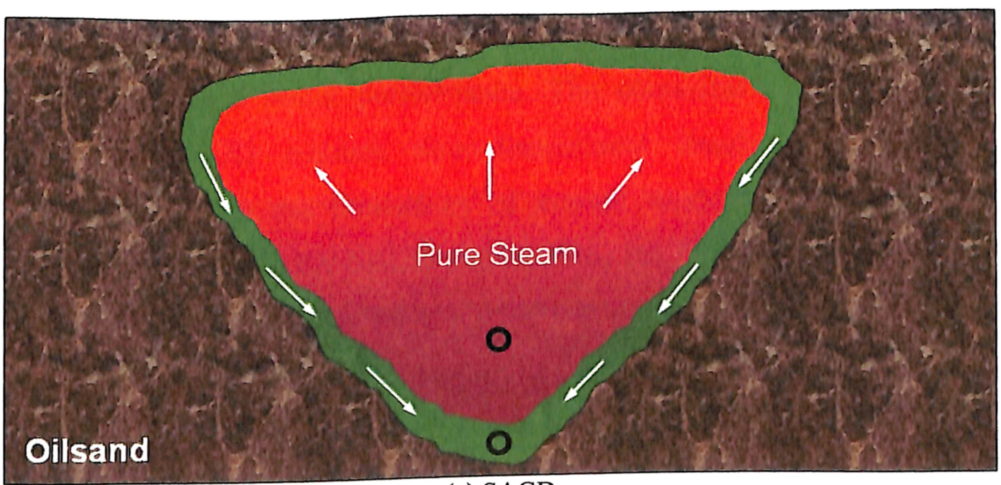
5. Foam-Assisted SAGD

The economic success of a SAGD process is based on two key operations, including the development of the steam chamber along the length of the injector and the effective control of the progress of steam for maintaining a liquid level between the injector and producer (i.e. control of steam traps). As mentioned in previous experiments showed promising results SAGD process high-quality, homogeneous reservoirs. For the fields with the intrinsic heterogeneity, however, the steam chamber are normally formed only around the well segment and surrounded by high permeability formations. The resulting low sweep efficiency is resulted in substantial reduction in the rate of production of oil and total oil recovery. Injectivity variations along the horizontal injection also complicates the steam feed control. To overcome these difficulties, we propose the use of foam to divert vapor steam live in areas of high permeability and slow progress of steam. Here we talk about the basic idea of foam pass SAGD (FA-SAGD), and their potential advantages over conventional SAGD process. Additional treatments added to the previous foam simulator to simulate processes and FA-SAGD SAGD described. After giving the details of the reservoir simulation model of synthesis, simulation test newly developed foam for SAGD type simulations by comparing the oil production rates predicted by the numerical simulation and analytic theory of Butler. The following simulation results done in Canada in the FA-SAGD and SAGD are shown and discussed to illustrate the difference in the performance of the two processes.

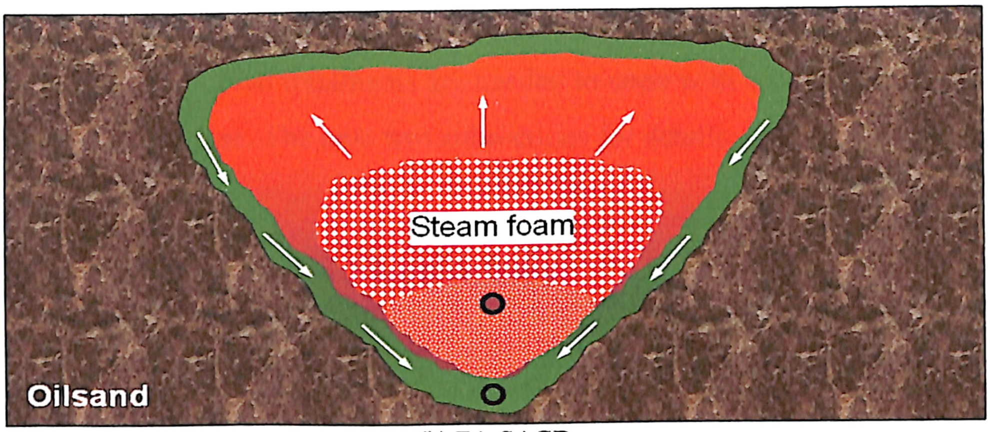
5.1 Concept of Foam-Assisted SAGD

The idea of the FA-SAGD originates from the singular behavior of the foam flowing in porous media. In an FA-SAGD process, the surfactant solution is co injected either continuously or intermittently, with steam in a reservoir to generate steam foam instead of the typical SAGD and torque settings. Steam foam during operation of SAGD improve the performance in the following ways:

The first mechanism is due to the strong dependence of the texture of the foam in the saturation of the liquid phase resulting in a favorable change in depth of the steam chamber. Figure 12 shows the expected distribution of water vapor and steam foam inside the steam chamber for SAGD and FA SAGD, respectively, in vertical cross section perpendicular to the direction of horizontal wells. Due to gravity, dry steam or steam quality is high on the top of the steam chamber. In the bottom of the steam chamber, the vapor becomes more humid, because the liquid water moves downward and gets collected in the buoyancy forces. The variation in the quality of steam in the steam in the SAGD process is illustrated in the colors of Figure 12 (a). The bright red color indicates high quality steam and shadow (dark) red color means the low steam quality. The rate of foam generation, increases proportionally with the speed of liquid phase This dependence on foaming and vapor distribution quality described above make it very clear that if the steam and surfactant solution is proposed for a process co injected FASAGD, strong (good) foam can be created in the bottom of the steam chamber, i.e. mainly in the region between the wells as illustrated in previous weak (secondary) foam that is expected in the top of the steam chamber. The presence of strong steam foam usually produces an increased flow resistance to the flow of steam. Therefore, the FA-SAGD process, existing high flow resistance in the region between wells to reduce the vapor flowing into the production well and control what the steam trap much easier to achieve.



(a) SAGD



(b) FA-SAGD

Figure 12: Schematic of (a) SAGD and (b) FA-SAGD.

The second mechanism is based on the potential for foam to partially block the oil-depleted high permeability regions and divert the flow of steam in low permeability. For a heterogeneous reservoir, the permeability of the formation may vary considerably along the horizontal wells are typically for the flight of 500-1000 m. For steam injection only, such variation usually the injectivity inconsistent throughout the length and which, in turn, causes uneven development vapor chamber. By injecting steam, along with a small quantity of surfactant, the foam can generate strong site in the segments of high permeability. The flow resistance resulting from the high permeability of steam flow areas of the blocks and the rerouting of steam to the regions of low permeability. The effect of diversion of foam, including steam injection profile along the well, which results in a uniform development of the steam chamber and a better performance. The numerical evaluation of the second mechanism of FA-SAGD requires three-dimensional simulation with heterogeneous reservoir settings. Due to the limitations of current models, we focus only on two-dimensional simulation of the FA-SAGD and examine the first mechanism described above to demonstrate the benefits and feasibility of sparkling water vapor in SAGD

5.2 Additional Treatments for FA-SAGD Simulation

The FA-SAGD process involves the water-oil vapor three-phase flow and transient temperature in the reservoir. According to the experimental observations reported in the literature, both the presence of oil phase and temperature changes affect the flow behavior of foam. Therefore, additional treatments are needed to cope with such effects in the simulation of the FA-SAGD process. The next two subsections for details.

5.3 Effect of Oil on Foam Mechanisms

The presence of oil destabilizes foam. Several researchers observed that the pressure gradient in flowing foam decreases with increasing oil saturation. This indicates that the flow resistance of the foam decreases and that the rate of foam coalescence increases. Generally in these studies, the pressure gradient gradually increases as oil saturation decreases from about 0.40 to 0.15 and then sharply increases to near the pressure gradient of oil-free foam as the oil saturation further decreases from 0.15 to 0.05. According to those observations and the pinch-off mechanism theory, Myers and Radke (2000) suggested a complicated function, particularly for the case at residual oil saturation, for the foam coalescence rate. Nevertheless, for simplicity, we incorporate the following expression to address the additional foam coalescence due to the presence of oil

$$r_{co} = k^0_{-2} \left(\frac{S_o - S_{or}}{S_{oi} - S_o} \right) |v_f| n_f \quad ,$$

where k0-2 is the number of sites in the gas-oil-gas volume and the other variables have their usual definitions. Myers and Radke (2000) argued that the numbe of residual oil globules of gas volume increases with decreasing pore size or permeability and therefore k-2 increases with decreasing must permeability.

5.4 Mass Balance of Surfactant

The concentration of surfactant in the wet phase (i.e. the aqueous phase in this study) determines the stability of the foam bubbles newly generated and therefore directly affects the rate of coalescence of foam. The propagation velocity of surfactant in the aqueous phase is affected by the loss of adsorption on the rock surface and partition into a high oil phase. In the overall decline, the adsorption of surfactant with increasing temperature because the solubility increases with increasing temperature of surfactant. Furthermore, only adsorption losses are significant compared to the losses by partition in an oil phase. Therefore, we consider only the adsorption of surfactant on the rock in the current model. After Friedmann et al. (1991) work, we further assume that the adsorption of surfactant in the rock can be modeled with a Langmuir-type model and is not affected by foam sheets. The assumptions leading to the mass balance equation (on a scale) that is adopted here to keep track of the surfactant concentration:

$$\frac{\partial}{\partial t}[\phi S_w C_s + (1-\phi)\beta\rho_r \Gamma] + \frac{\partial}{\partial x}(u_w C_s) = C_s Q_w \quad ,$$

where C is the concentration of surfactant, _ is the surface area per unit rock mass_r is the density of the rock. Other symbols have their usual definitions. The adsorption of surfactant in the rock is modeled by

$$\Gamma = K_s A_s C_s / (1 + K_s C_s)$$

And

$$K_s(T) = K_s(T_0)\exp\left[-\frac{\Delta Q}{R}\left(\frac{1}{T_0} - \frac{1}{T}\right)\right] \quad ,$$

where it is a constant in the Langmuir model, T0 is the reference temperature, Ks (T0) is a constant value measured at the reference temperature, R is gas constant, and _q is the heat of adsorption changes.

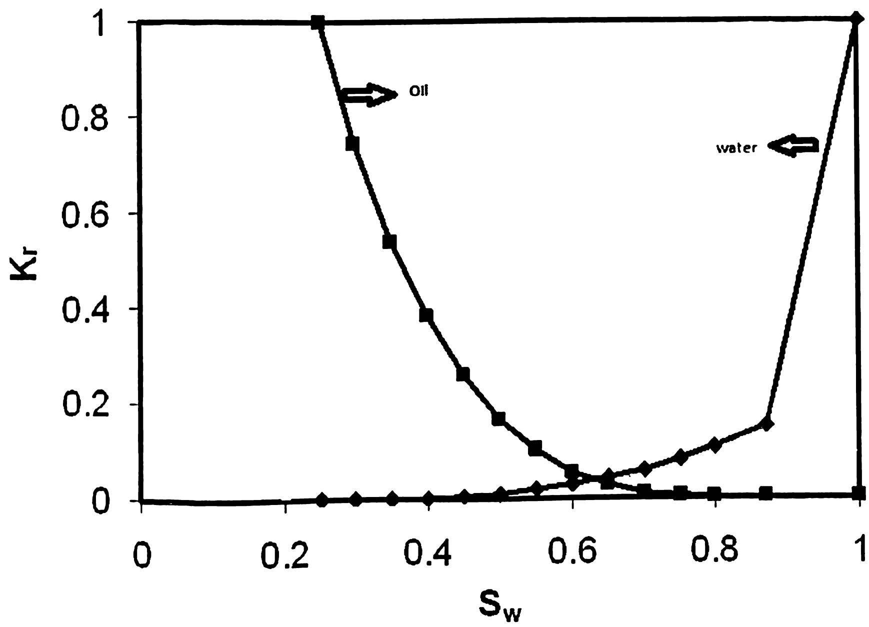
5.5 Reservoir Simulation Model

A synthetic oilsand deposit described by Butler (1998b) was adopted with minor changes to the numerical investigation of FA-SAGD. The reservoir pay zone is 20 m with a 1-D permeability, porosity of 0.33 and initial oil saturation of 0.75. The oil viscosity is 100,000 cp at reservoir temperature, 15 C, and reduced to 80 CP, when its temperature rises to 100 C. The initial reservoir pressure is 1,200 kPa. Following table summarizes the key reservoir properties, and the foam model and the relative permeablity curves are shown.

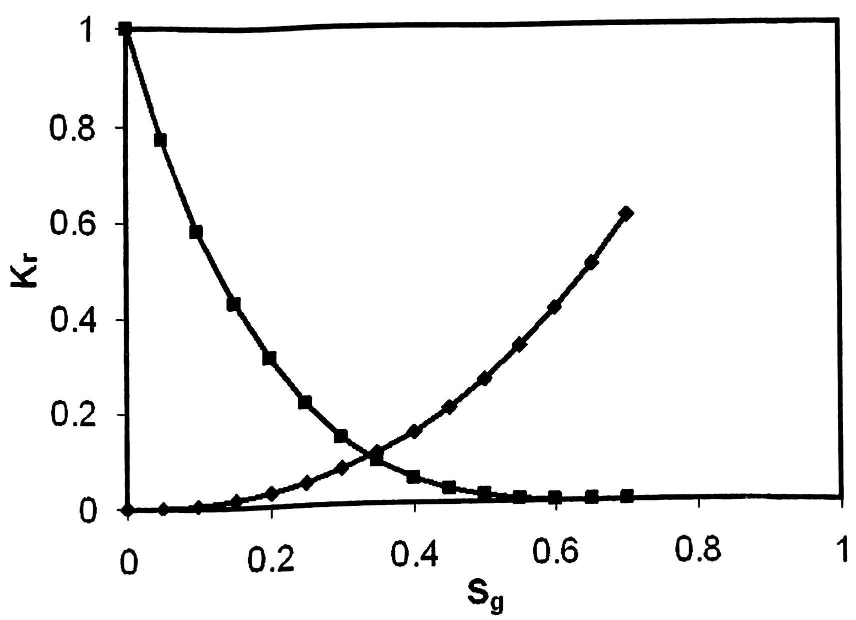
Reservoir properties	**Values**
Reservoir temperature	15c
Oil density	1.00 g/cc
Oil viscosity at T_{res}	100,000 cp
Oil viscosity at 100-C	80 cp
Reservoir thickness	20 m
Thermal diffusivity	0.07 m_2/day
Porosity	0.33
Residual oil saturation	0.13
Reservoir permeability	1.00 D
Initial reservoir pressure	1,200 kPa

In a commercial SAGD project, the field is usually carried by a series of horizontal well pairs at a lateral distance between 75 and 150 m. as described in earlier. Similarly, a confined reservoir simulation model is considered here. Because the element of symmetry and the assumption of a homogeneous system, the model only half of the repeating unit. A uniform grid system of 2 m × 2 m blocks of the network, as shown in the figure, is used to represent the vertical section of the reservoir for the numerical simulation. The dimension along the horizontal well is 1 m in model and production rates will be reported by the unit length basis. The border condition is assumed that no loss of flow and heat coating and underburden calculated by a semi analytical model developed by Vinsome and Westerveld (1980).

For both SAGD and SAGD FA-simulations presented below, the recovery process begins with a warm-up period of 3 months is usually required to establish hydraulic and thermal communication between the injection and production wells.



1) Water-oil system



2) Gas oil system

Figure 13: Relative permeability curves for SAGD and FA-SAGD simulations: (a)water-oil system and (b) gas-oil system.

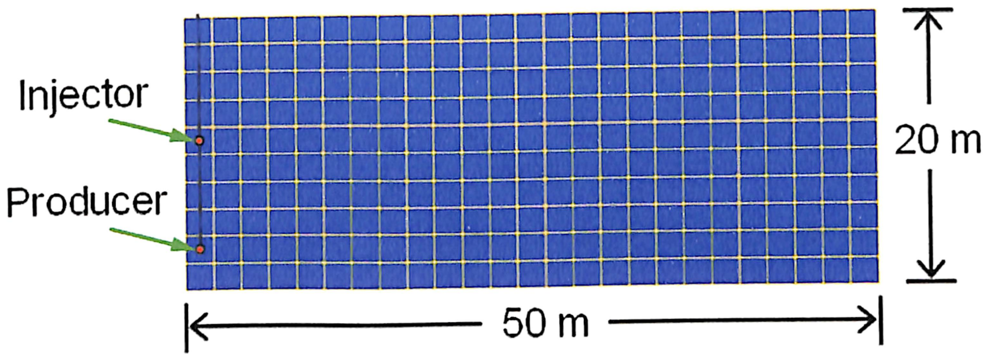


Figure 14- Geometries of the two- dimensional reservoir model using SAGD and FA-SAGD

After the oil between wells becomes mobile vapor, or steam and surfactant solution injectors at maximum pressure of 1,300 kPa and well production operated at a fixed minimum bottom hole pressure of 1,200 kPa. The simulation career ended after 15 years of operation.

5.6 FA-SAGD versus SAGD

Then include the option of modeling foam applied to simulate M2NOTS FA-SAGD process. A constant pressure of 1200 kPa production it sets the controls in the injection well and production well, respectively. The injected steam has a quality of 0.9 and the liquid portion of injected steam contains surfactant concentration of 1.0 wt%. Figure 15 shows the temperature profiles at different stages of production, as co injecting resulting vapor and surface solutions. Region with temperature equal to the steam temperature corresponding to the pressure of the steam out chamber. Steam saturation profiles given in Figure 16 confirm the bowl-shaped Steam chamber developed in the reservoir. Similarly, the SAGD process steam chamber FA-SAGD process, experience is growing, expanding, and depleting stages. A statement that the steam saturation profiles variation of steam quality of the steam chamber, i.e. the upper steam dryer and wetter steam the bottom of the steam chamber, corresponding to the analysis of steam quality distribution under effect of gravity is a typical SAGD process.

Due to the boundary conditions of confinement and thermal expansion caused by increasing temperature, as shown in Figure 17, the pressure builds up ahead of the steam chamber. The high-pressure zone moves outwards as the steam chamber spent and finally disappears. Within the steam chamber, considerable pressure gradients exist in the injection, indicating the presence of strong foam.

Figure 18 below shows the foam texture profiles of 300, 1000, 2000 and 5000 days injection predicted by numerical simulation. As expected, the steam chamber foam is full steam generated in situ and high pressure results gradient in Figure 17. It is worth noting that the steam foam texture is not uniform throughout the steam chamber. As shown in Figure 18, strong Steam foam is created and accumulates mainly in the region between wells. Foam becomes much thicker at the top of the steam chamber. This distribution the texture of the foam is the result of the variation in the quality of steam due to gravity in steam chamber.

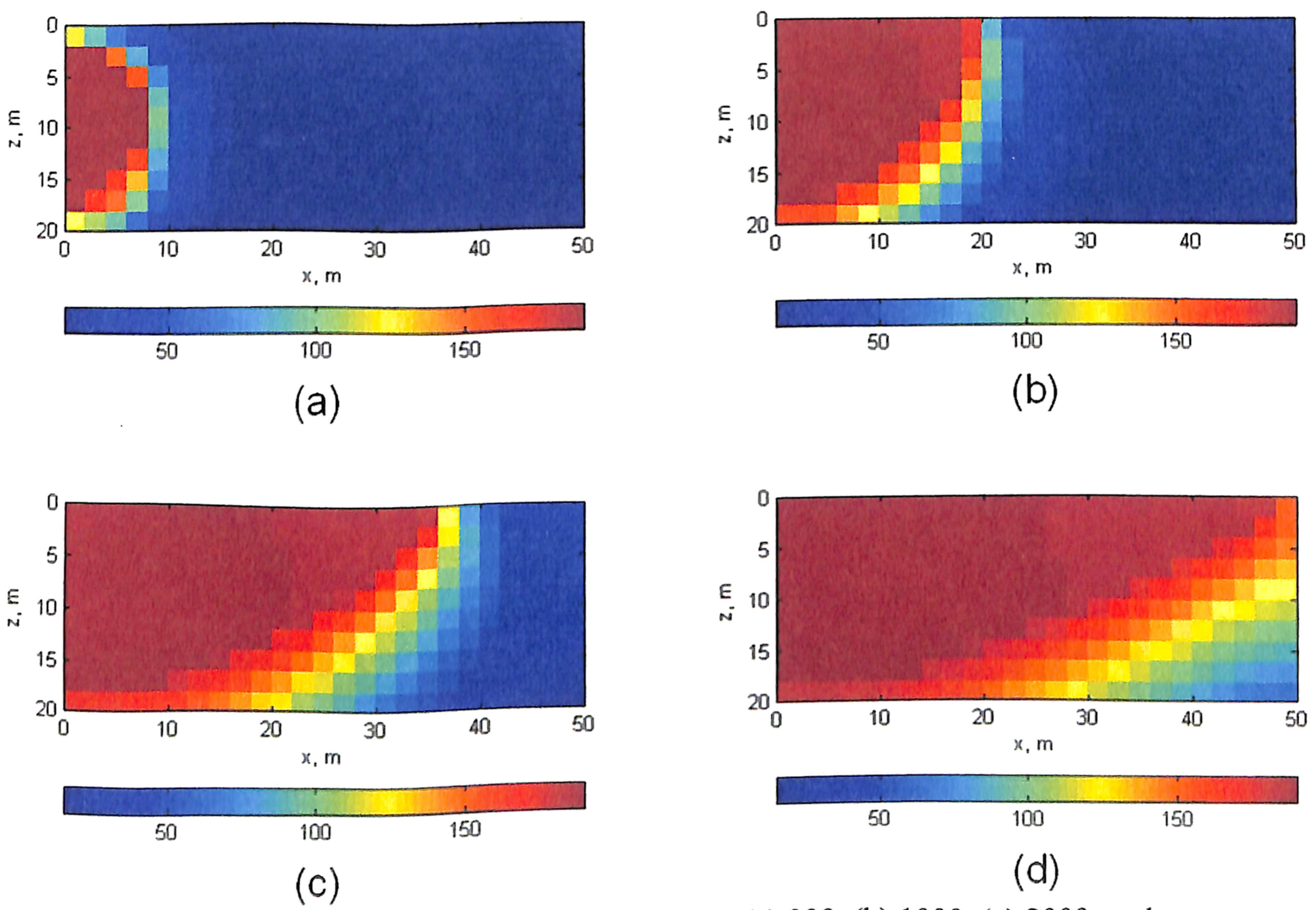


Figure 15: Temperature profiles during FA-SAGD at (a) 300, (b) 1000, (c) 2000, and (d) 5000 days. The colour bar gives temperature values in unit of _C.

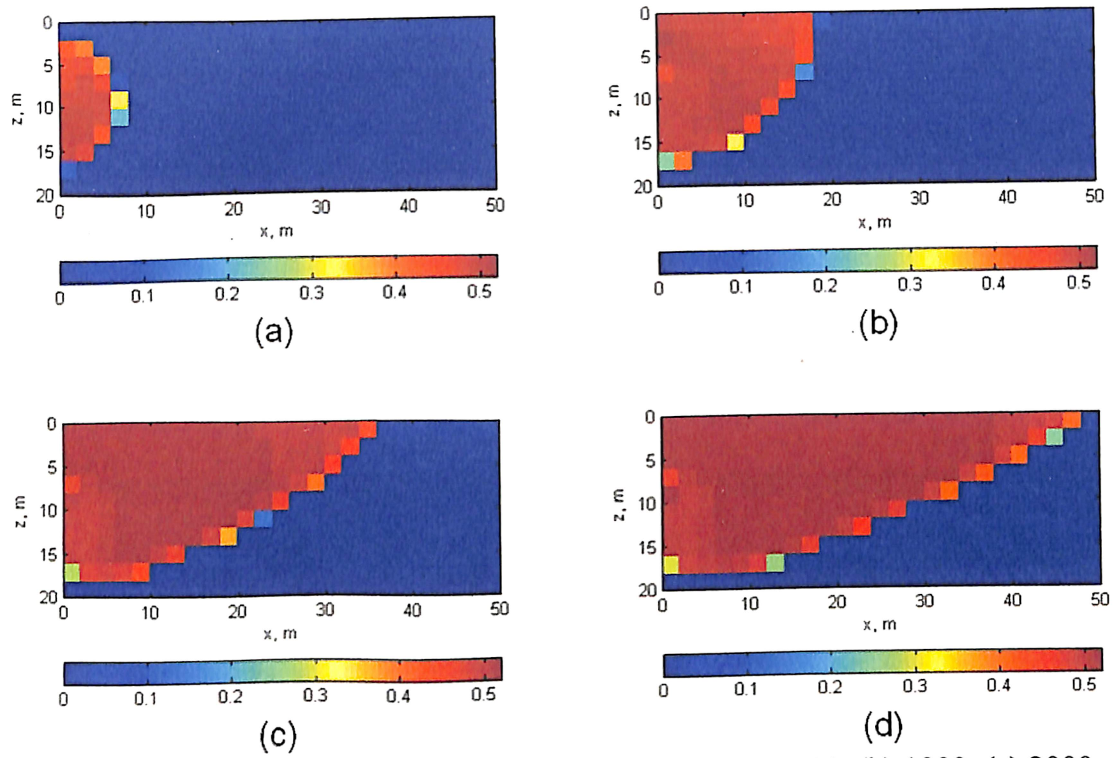


Figure16: Steam saturation profiles during FA-SAGD at (a) 300, (b) 1000, (c) 2000, and (d) 5000 days.

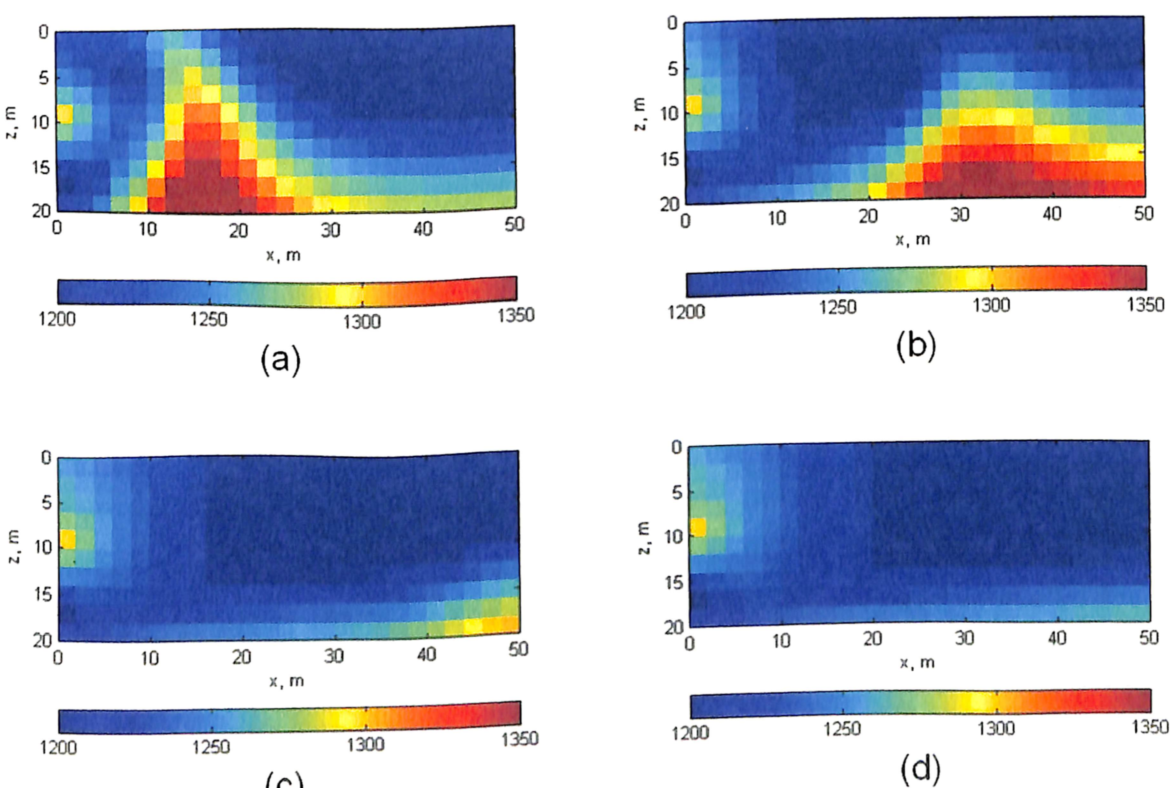


Figure 17: Pressure profiles during FA-SAGD at (a) 300, (b) 1000, (c) 2000, and (d) 5000 days. The colour bar gives pressure values in unit of kPa.

The fine texture in the steam foam edge of the chamber is attributed to the net foaming due to acute changes phase loadings across the border.

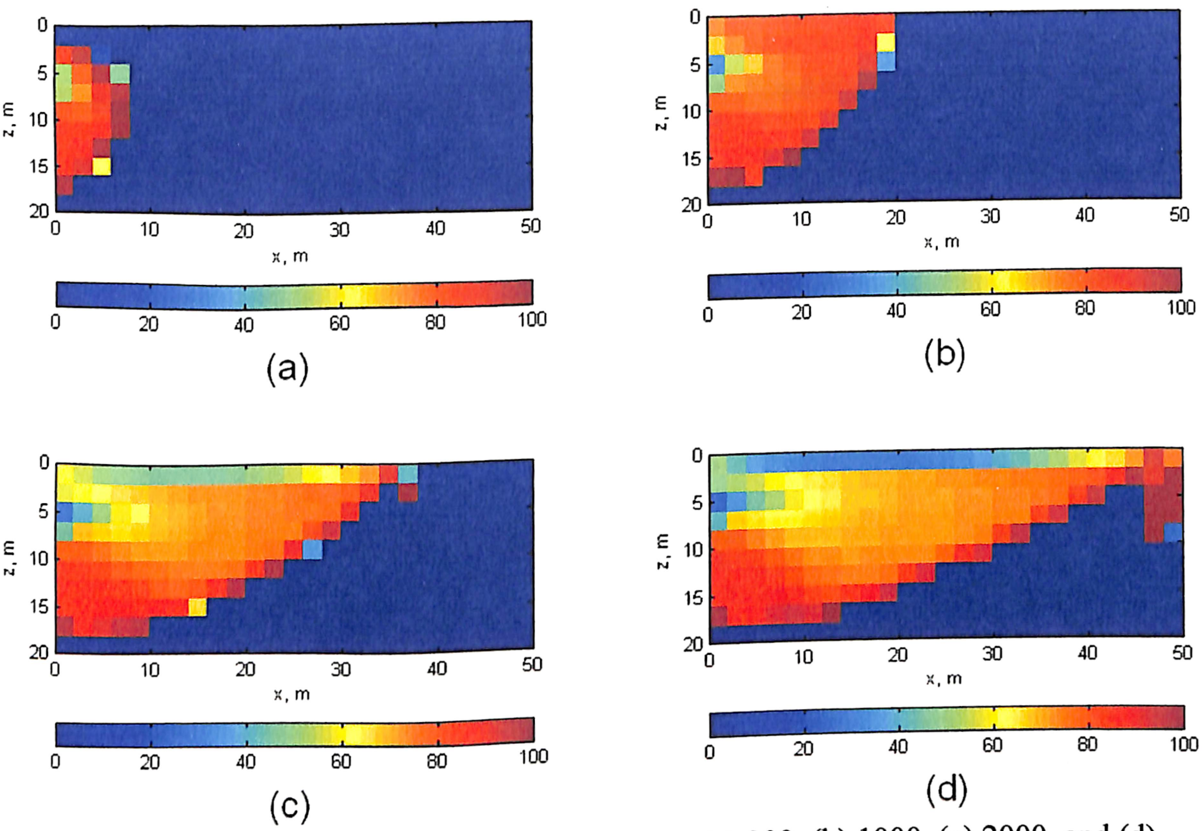


Figure 18: Foam texture profiles during FA-SAGD at (a) 300, (b) 1000, (c) 2000, and (d) 5000 days. The colour bar gives foam texture values in unit of mm^{-3}.

As shown in Figure below, the oil inside the steam chamber runs efficiently and remaining oil saturation is close to the residual oil saturation. Water saturation profiles presented in Figure 19 clearly show the steam condensation zone is over the limit of the steam chamber. The condensed water flows with the hot oil in a direct current flow along the slopes of the steam chamber to the production well. This direct current flow contributes to the bulk of oil production. Simulation runs for the case SAGD operating in exactly the same conditions

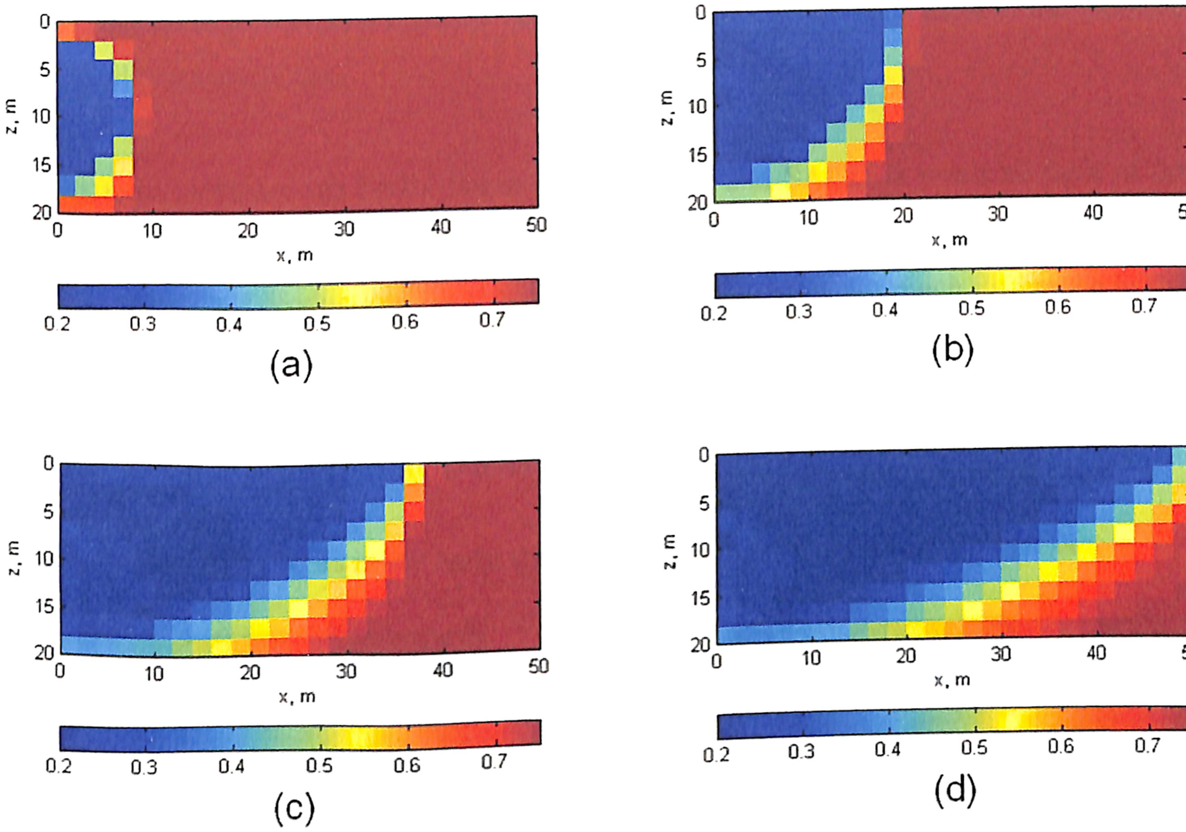
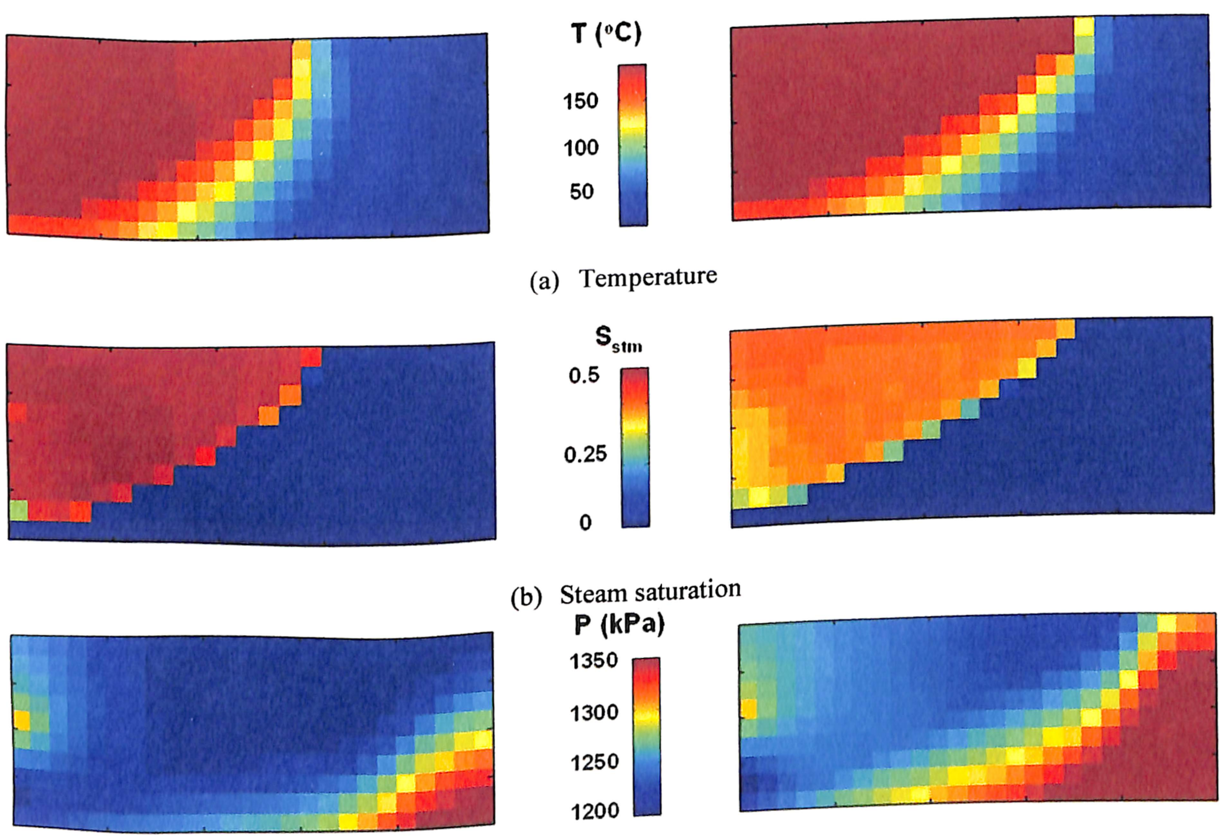


Figure 19: Oil saturation profiles during FA-SAGD at (a) 300, (b) 1000, (c) 2000, and (d) 5000 days.

Figure below provides side by side comparison profiles of the key parameters, including temperature, saturation vapor pressure and oil saturation at the same recovery (ie, 40%) between FA-SAGD and SAGD. Two main differences between FA-SAGD and SAGD are identified by this comparison. First, FA-SAGD steam chamber has more bowl-shaped, while the top ahead of the steam chamber in the case SAGD extends laterally beyond, resulting in chamber flat plate-shaped. This difference in the form of vapor chamber may cause heat loss at different overburden and therefore giving different energy efficiencies. Theoretically, the loss of heat to the overhead is proportional to the temperature gradient, thermal diffusivity, and the contact area. The bowl-shaped vapor chamber in the case of FA-SAGD has a lower temperature area overhead exposure compared with the plate-shaped chamber in SAGD. Therefore, it is expected FA-SAGD to be more energy efficient. Second, the remaining oil saturation in the steam the camera is lower in FA than in SAGD SAGD. This occurs because the presence strong steam foam inside the steam chamber in the FA-SAGD causes high blood pressure slopes leading to the oil phase to flow even near the oil saturation to very low residual value. The reduction in oil saturation of the increase in final oil recovery factor.

Figures more compare the performance of FA-SAGD and SAGD in terms of rates of oil production, steam injection and production rates, and cumulative steam injection compared with cumulative oil production. As shown in Figure 20, there is not much difference in the rate of oil production between SAGD and SAGD FA, i.e. at the initial stage, during the first 500 days. In the later stage, however, oil production rate curve FA-SAGD is less than SAGD until the case goes to SAGD production depleting due to the limit effects.

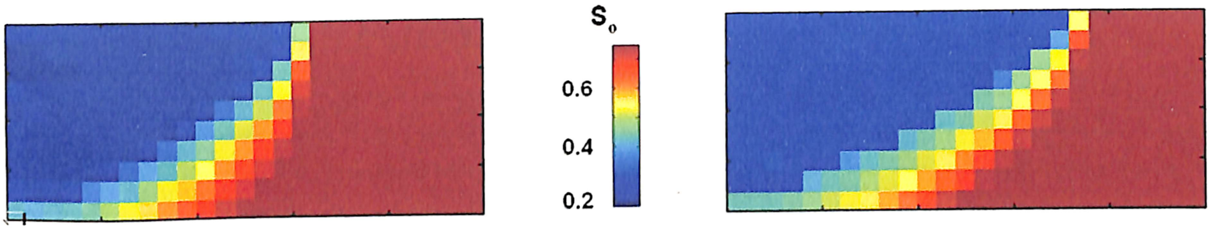
Countercurrent flow exists in the early stage of steam chamber expansion, whereas



(a) Temperature

(b) Steam saturation

(c) Pressure



(c) Oil saturation

Figure 20: Comparison of FA-SAGD and SAGD: (a) temperature, (b) steam saturation,(c) pressure, and (d) oil saturation. The profiles on the left column are for FA-SAGD and the ones on the right column are for SAGD.

6. CASE STUDY

Reservoir Data

Porosity	17%
Gross height	9.4ft
Youngs Modulus	19310000
Possions Ratio	0.15
Permeablity	10md
Total compressiblity	0.00000057/kpa
Reservoir Pressure	22063kpa
Fracture Gradient	13.6 kPa/m

Fracturing fluid properties

ή	.58
K'	2.47E+0 Pa.s^n
Foam Type	None
Thermal Expansion (Ct)	0.00007 1/°F
Fluid Compressibility (Cp)	0.00013 1/psi
Gel Stability	Low Degradation

Drilling/Wellbore information

Injection Path	Tubing
Measured Depth	2133.6 m
Tubing outside Diameter	73.0mm Grade N80
Tubing inside Diameter	62mm Grade N80
Pumping flow rate	1.91 m3/min
Hole size	222.3 mm
Casing outside Diameter	114.3mm Grade N80
Packer depth	1767.8 m

Assume the following design considerations to compare the fracture properties for the various models.

Flowrate=1.91 m3/min, total proppant =3400 lbs, total pumping time =50 min, total clean fluid volume =86 m3, pad volume = 35% total fluid volume. Assume water fractures are preferred and 16/30 Jordan may be used to prop opens the fracture

Formation Properties

TVD	TYPE	GROSSHT	LKOFFHT	NETHT	PERFS	PRFDIA	FRACGRAD	INSITUSTRESS	YM	POISSON	RESVRPRESS	K	PORO	FRCTOUGH	ACRES	GS%	OIL%	H2O%	MD	specific gravity	
1827.6	SHALE	30.5	30.5	0	0	11.4	17.2	31681	3.10E+07	0.18	19995	0.1	6	1319	65	0	15	85	1827.6	2.3	0
1858.1	CLEAN SANDST	9.4	9.4	9.4	47	11.4	13.6	25282	1.93E+07	0.15	22063	10	17	1099	65	0	15	85	1858.1	2.65	0
1867.5	SHALE	30.5	30.5	0	0	11.4	17.4	32793	4.55E+07	0.25	19995	0.01	4	1319	65	0	15	85	1867.5	2.3	0

Objective - To design a fracture for the given reservoir using a stimulator using P3D fracture model.

The proppant schedule is as follows

stage name	pump rate		gel conc	fluid vol	prop conc	prop mass	slurry vol	pump vol
PAD	1.91	YF120LG W	2.4	30.3	0	0	30.3	15.9
1.0 PPA	1.91	YF120LG W	2.4	5.3	119.7	637	5.6	2.9
2.0 PPA	1.91	YF120LG W	2.4	7.3	239.6	1745	7.9	4.2
3.0 PPA	1.91	YF120LG W	2.4	7	359.3	2512	8	4.2
4.0 PPA	1.91	YF120LG W	2.4	6.7	479.3	3221	7.9	4.2
5.0 PPA	1.91	YF120LG W	2.4	6.5	599.1	3875	7.9	4.2
6.0 PPA	1.91	YF120LG W	2.4	7.5	719	5381	9.5	5
6.5 PPA	1.91	YF120LG W	2.4	9.3	778.9	7283	12.1	6.4
FLUSH	1.91	WF120	2.4	6.1	0	0	6.1	3.2

The final summary of the designed fracture is given below-

Max Hyd Frac length	133.7m
Proppant frac half length	117.5m
Average propped width	1.8mm
EOJ net pressure	7505kpa
Effiency	0.436
FCD	1097

Simulated Results using FracCade 5.1 (Schlumberger):

The properties were run on the stimulator Fraccade 5.1 of schlumberger and the various logs were plotted as under.

The designed fracture looks like the below figure.

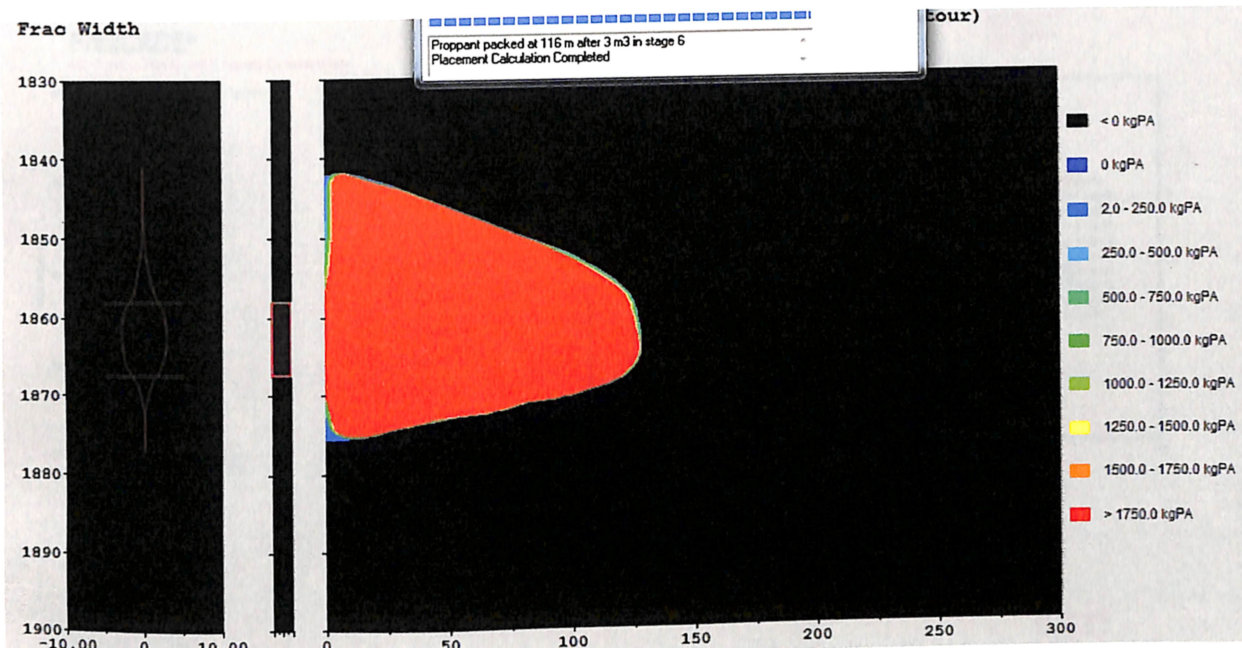


Figure 21:The facture model showing the width and the concentration of Fracture fluids in the fracture contour.

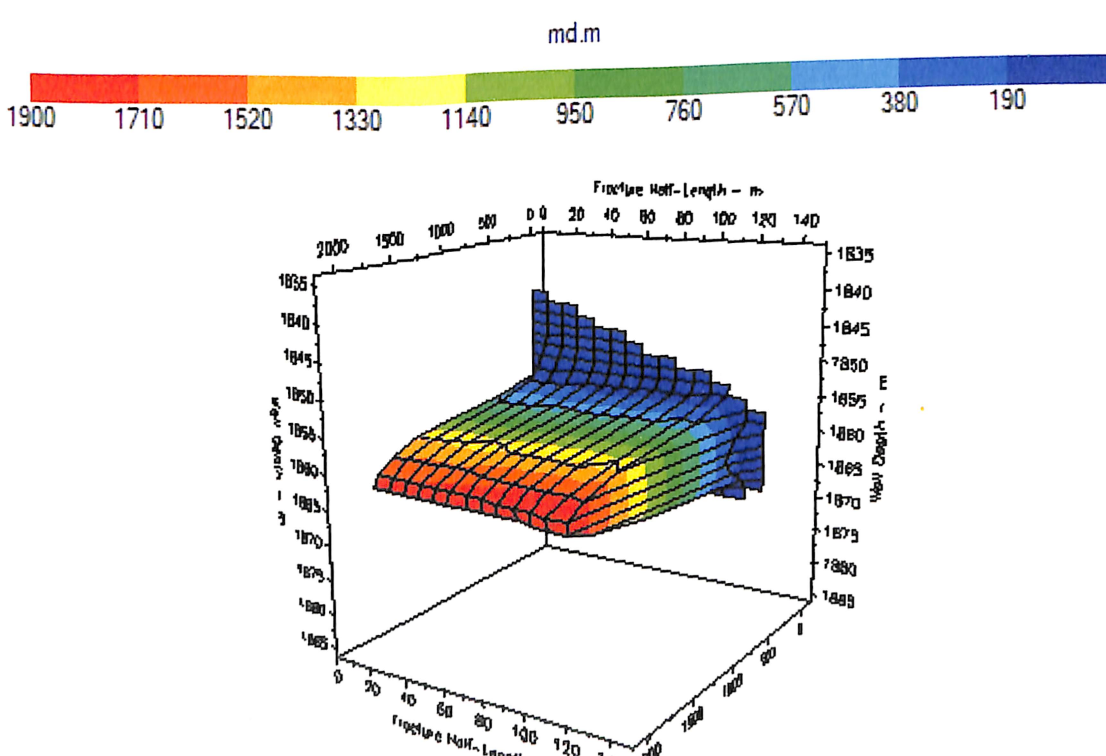


Figure 22:Conductivity contour

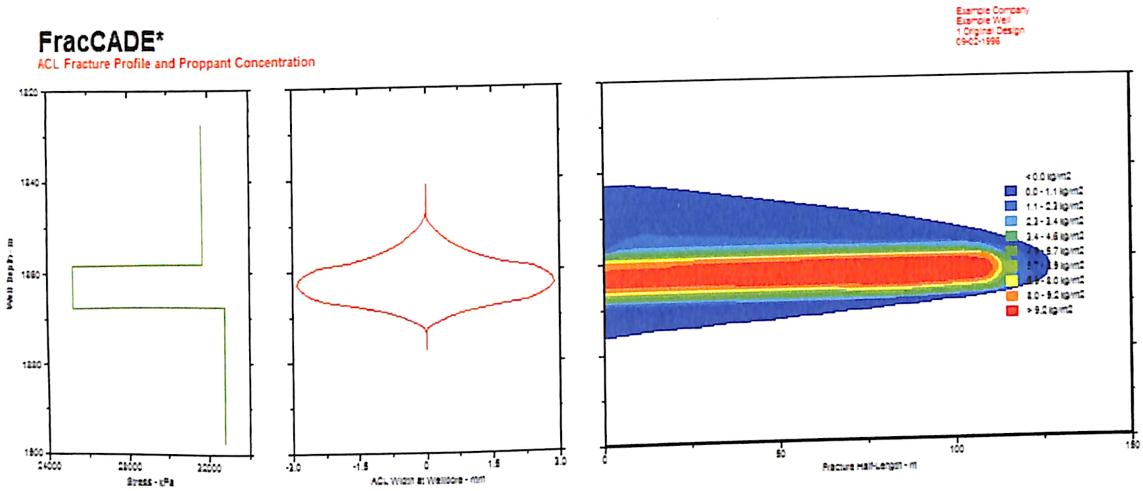


Figure 23:Proppant concentration contour

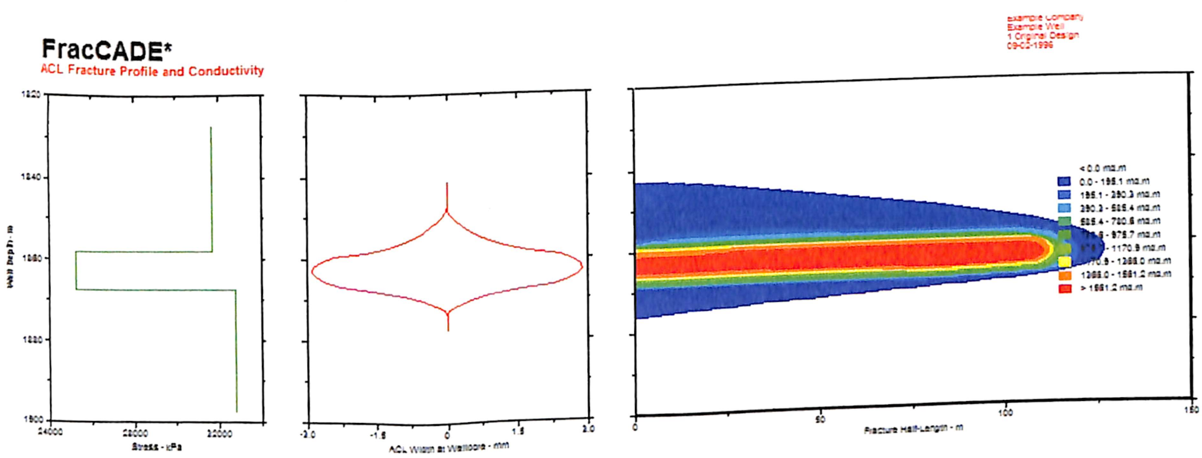


Figure 24:Fracade conductivity contour

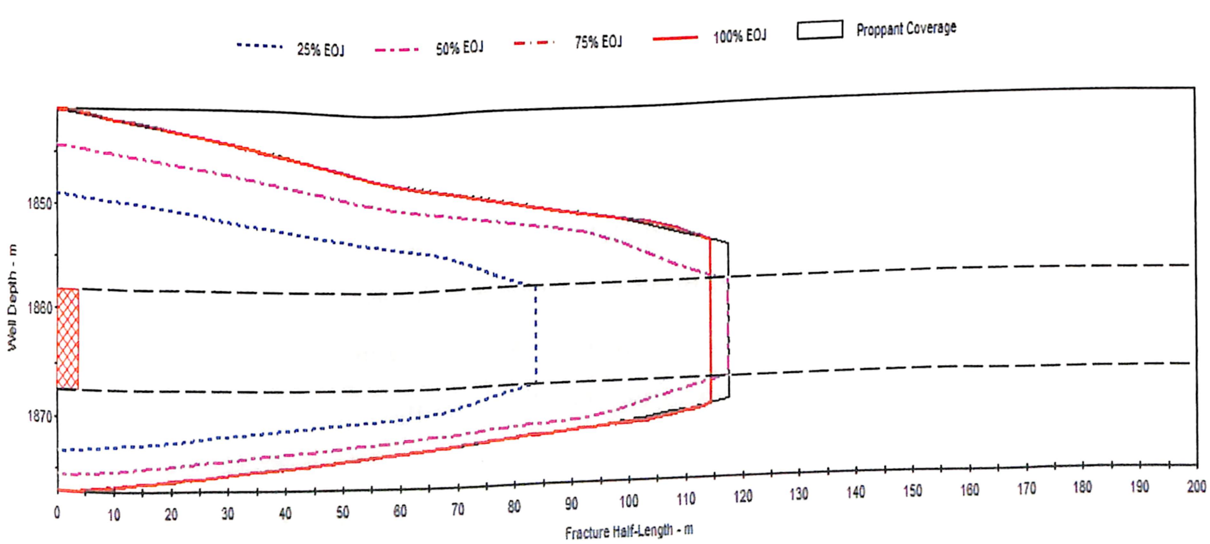


Figure 25:Fracture geometry

7. RESULTS AND DISCUSSION

This report addressed the role of reservoir heterogeneities on SAGD performance and proposed two approaches, hydraulic fracturing and deployment of aqueous foams, to improve the conventional SAGD process in heterogeneous reservoirs. Due to the lack of STAR simulator we provided an analytical case study on hydraulic fracturing of the reservoir.

Hydraulic fracturing improves steam injectivity dramatically to achieve an economical oil production rate in a SAGD process for reservoirs with poor vertical communication. The orientation of hydraulic fractures generally depends on the depth of the formation. Fractures are usually horizontal for shallow SAGD projects and vertical for deep SAGD projects. Vertical hydraulic fracture enhances SAGD performance considerably and thus hydraulic fracturing may be desirable for deep SAGD projects. It is also found that a vertical hydraulic fracture along the well direction is superior to a direction perpendicular to the well direction. The field practice that a horizontal well is drilled along the direction of the maximum horizontal stress to ensure well stability coincides with the requirement of vertical hydraulic fractures parallel to the well direction. Moreover, for the case of vertical fractures along the well direction, we propose a modified well configuration with injectors and producers off-set laterally at a short distance to mitigate the difficulty in operations for steam trap control while maintaining effective oil production. At early stage of the SAGD process in fractured system, steam moves through the fractures first and then the matrix blocks are heated primarily by conduction and possibly some steam invasion. The steam-oil interface forms and develops from all sides of the matrix and oil chamber rather than a steam chamber forms and shrinks in the center of each block. SAGD process recovery enhanced in the presence of vertical fractures but horizontal fractures were harmful on the recovery. Fracture spacing was not a very important parameter in the performance of steam processes in fractured models. High fracture frequency improved SAGD performance since it reduced the time period necessary for heating the matrix block and enhanced heating process by conduction. Horizontal fractures between injector-producer wells had an insignificant effect on the process since SAGD production mechanism is based on steam chamber development in

AWR rather than NWR. Horizontal fractures extension increase reduced ultimate oil recovery attainable by SAGD. In the networked fracture model the presence of vertical fractures improved the recovery achieved in the case of horizontal fractures alone.

As cmg stars was not available for simulation we only designed a fracture using Fracade by schlumberger. The results of the fracture design were plotted above.

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