APPROVAL CERTIFICATE

This final year project paper entitled

"Numerical modeling for heat transfer coupled with the fluid flow during cyclic steam stimulation"

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Numerical modeling for heat transfer coupled with the fluid flow during cyclic steam stimulation

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Abstract— By increasing in the use of nonrenewable energy and decreasing in discovering hydrocarbon reservoirs, in near future the world will encounter with a new challenge in the field of energy, so increase in recovery factor of the existing oil reservoirs is necessary after the primary production. In one hand the existence of untouched heavy oil reservoirs in Iraq and lack of producing from them and maturity of light oil reservoirs to 2nd and 3rd stage of their production age in other hand make the development and production of these heavy oil reservoirs necessary in Iraq. The goal of this study is to survey common methods of producing oil reservoirs and emphasizing the advantages and limitations of these methods' appliance in heavy oil reservoirs of Iraq. One way to choose an optimized method is the comparison of reservoirs' parameters in successful EOR projects with the considered reservoir. However, it should be consider that each reservoir has its especial characteristics and we cannot give certain idea about it. The set of thermal ways and other ways and new technologies and an introduction about oil recovery in fractured reservoirs are studied. The most common way for recovery of heavy oil reservoirs' is thermal ways which have the most usage in the recovery of the world's heavy oil and among these; steam injection in different ways with the most amount of oil production has terrific importance. Other thermal ways such as thermal combustion and electromagnetic and electric heat in practice, some studies and experiments have been doing in reservoirs. The correct ways especially in heavy oil reservoirs in order to improve and increase oil recovery have been studied, for example we can point to wells technology. The gained results show that the best way for recovery heavy oil thermal way and especially steam injection (under optimum conditions of quality and steam nature and the model of production and injection wells paths). Steam modeling by activating gravity drainage drive process by using steam. This method, also known as the Huff and Puff method, consists of 3 stages: injection, soaking, and production. Steam is first injected into a well for a certain amount of time to heat the oil in the surrounding reservoir to a recover approximately 20% of the original oil in place (OOIP), compared to steam assisted gravity drainage, which has been reported to recover over 50% of OOIP. It is quite common for wells to be produced in the cyclic steam manner for a few cycles before being put on a steam flooding regime with other wells. In this project, we worked firstly to collect information about the fields in which cyclic steam was applied around the world. Secondly, we simulated the periodic injection processes using CMG software. Thirdly, we changed some properties of the reservoir permeability, porosity and thickness to find any factor affecting the performance of the cyclic process.

I. INTRODUCTION

Generally, oil recovery options are divided into 3 main stages: primary, secondary and tertiary. Historically, the oil and gas industry describes these 3 stages of oil recovery in a chronological sequence. In the initial oil production stage, the primary oil recovery is resulted from displacement energy that occurs naturally in a reservoir. These natural driving mechanisms include depletion drive, gas cap drive, water drive and combination drive. After noticeable reduction in the initial oil production rate, secondary oil recovery takes place. The main purpose of secondary oil recovery is to control the pressure in the reservoir to maintain or increase the oil production rate by introducing external fluid to the reservoir. It is usually done with processes like water flooding or gas injection. Commonly, recovery factor from primary and secondary oil recovery is only around 20 – 40% and is affected by the reservoir rock properties, fluid properties as well as geological heterogeneities (Romero-Zerón. 2012). The third stage of the production, tertiary oil recovery, happens when the cost to production ratio of secondary oil recovery process is no longer economical. The ultimate intention for tertiary oil recovery is to improve the overall oil efficiency. In tertiary oil recovery, the recovery factor is about 30 – 60% (Sino Australia Oil and Gas Ltd, 2013). Also known as enhanced oil recovery, tertiary oil recovery increase hydrocarbon production by altering the formation properties for conducive extraction (Needham and Doe, 1987). The true meaning of enhanced oil recovery is the ultimate oil recovery that can be recovered from a reservoir in a cost-effective manner on top of the oil economically recovered from primary and secondary recovery oil processes. Over the years, research and pilot testing have been conducted to further develop different methods of enhanced oil recovery. These methods include thermal recovery and non-thermal methods, which consist of chemical flooding, miscible flooding, immiscible gas drives and microbial enhanced oil recovery. In cyclic steam stimulation (CSS), steam is injected into a production well for a period. Then the well is shut in and allowed to soak by steam for some period before it returns to production. The initial oil rate is high because of high initial oil saturation, high increased reservoir pressure, and lowered oil viscosity. As the oil saturation becomes lower, the reservoir pressure becomes lower and the oil viscosity becomes higher due to heat losses to the surrounding rock and fluids, oil rate declines. At some point, another cycle of steam injection is initiated. Such cycle may be repeated several times or many times. The terms of steam soak and steam huff-and-puff (huff-n-puff, huff 'n' puff) are also used to describe CSS, we will first briefly discuss CSS mechanisms, theories to estimate production performance, and screening criteria. After that we will focus on practice and field cases of CSS projects.

II. Oil Recovery methods:-

II.I. Primary Recovery

First stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir, into the wellbore and up to the surface. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economical, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically around 10% for oil reservoirs.

II.I.I. Primary Recovery Mechanisms

The recovery of oil by any of the natural drive mechanisms is called "primary recovery." The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

1. Rock and liquid expansion drive
2. Depletion drive.
3. Gas cap drive
4. Water drive
5. Gravity drainage drive
6. Combination drive.

II.II Secondary Recovery

Second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and water flooding. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form or enhanced recovery. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place.

II.II.I. Secondary Recovery Mechanisms

a- **Water injection:** In a completely developed oil or gas field, the wells may be drilled anywhere from 60 to 600 m (200 to 2000 ft) horizontally from each other, depending on the nature of the reservoir. If water is pumped into alternate wells (i.e., water injection wells) in such a field, the pressure in the reservoir as a whole can be maintained or even increased. In this way, the daily production rate of the crude oil can be increased. In addition the water physically displaces the oil, thus increasing the recovery efficiency. In some reservoirs with a high degree of uniformity and little clay content, water flooding may increase the recovery efficiency to as much as 60 percent or more of the original oil in place. Water flooding was first introducing in Pennsylvania oil fields, somewhat accidently, in the late nineteenth century, and now has been used throughout the world.

b- **Steam injection:** Steam injection is used in reservoirs that contain very viscous oils, i.e., those that are thick and flow slowly. The steam not only provides source of energy to displace the oil, it also causes a marked reduction in viscosity (by raising the temperature of the reservoir), so the crude oil flows faster under any given pressure differential.

c- **Gas injection:** Some oil and gas formations contain large quantities of produced natural gas and carbon dioxide (CO2). This gas is typically produced simultaneously with the liquid hydrocarbon production. The natural gas or CO2 is recovered, recompressed and re-injected into the gaseous portion of the reservoir. The re-injected natural gas or CO2 maintains reservoir pressure and assists with pushing additional liquid hydrocarbons out of the liquid portion of the reservoir.

III. Heavy oil reservoir recovery methods

Heavy oil definition Heavy oil and bitumen are defined as crude oil with high viscosity and low API degree. In general, crude oil with a viscosity (μ) $\geq$ 1 kg/m.s or API $\leq$ 20 is classified as heavy oil, and crude oil with $\mu \geq$10 kg/m.s and API $\leq$10 is classified as bitumen. As the world's reserves for sweet crude oil decline rapidly and demands for petroleum resources continue to increase, the role of heavy oil and bitumen is crucial to the future of the world's petroleum supply.

Table 1 heavy oil definition (International Energy Agency)2016.

Oil type	Viscosity (cp)	Density (kg/m^3)(15.6^{o}c)	API degree 15.6^{o}c)
Heavy	100-1000	394-1000	10-20
Ultra heavy/Bitumen	>10000	>1000	<10

The world's proven reserves for non-conventional oil are approximately 8 trillion barrels, approximately 3 times larger than the world's reserves of conventional oil (Dusseault, 2006). As techniques in heavy oil recovery improve over time, the world's proven reserves for non-conventional oil are expected to increase as well. Out of the total 8 trillion barrels of non USA 500 billion bbl Russia 600 billion bbl Middle East 530 billion bbl Venezuela 2 trillion bbl Canada 3 trillion bbl 2 conventional oil reserves, Canada and Venezuela possess 3 trillion and 2 trillion barrels respectively. Even though Canada has most of the heavy oil reserves in the world, the high in-situ viscosity and the low API makes their recovery a challenge.

Table 2 -Known resources of heavy oils in the world(NIOC)2016.

Country	The rate of in-situ oil (10^9 bbl)	Country	The rate of in-situ oil (10^9 bbl)
Canada	1860	Syria	14
Venezuela	1200	China	10
Russia and prior Soviet republics	1200	Ecuador	7
America	55	Trinidad & tobacco	5
Iran	50	Colombia	3
Iraq	34		

III.I. Recovery of Heavy Oil

The world's reserves of non-conventional oil are approximately 3 times that of conventional oil, but only 13% of the world's crude oil production is non-conventional oil. The high capital investment and high operation cost in heavy oil recovery are the reasons. In Canada, in order to sustain an economical heavy oil production operation.

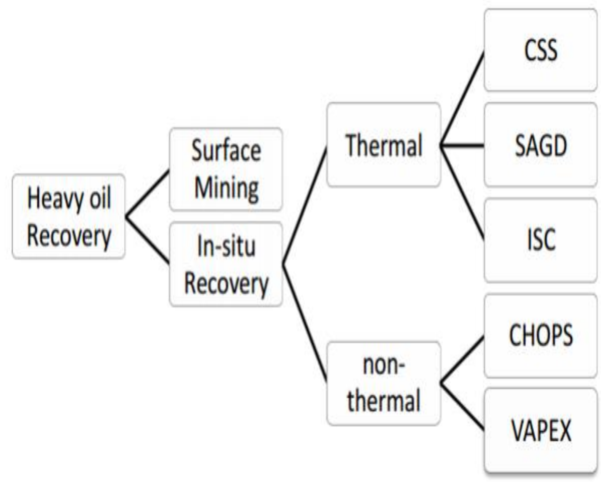
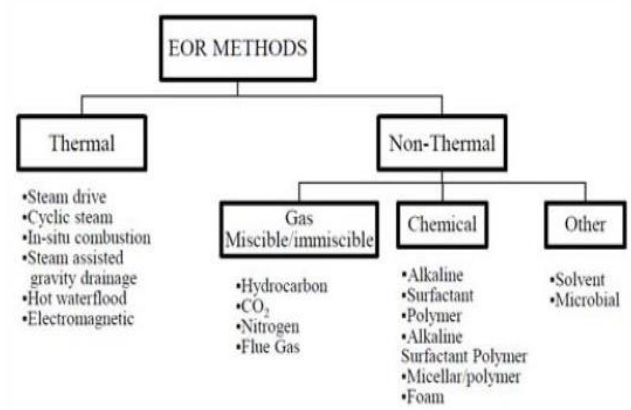


***Figure 1- Recovery of heavy oil (** *Maria Teresa 2016)*

IV. Enhanced Oil Recovery

is the process of increasing the amount of oil that can be recovered from an oil reservoir, usually by injecting a substance into an existing oil well to increase pressure and reduce the viscosity of the oil With a conventional oil well, natural pressure in the reservoir pushes the oil to the surface or a pump is used to create the pressure. This usually results in a recovery of about 25% of a well's oil reserves. Enhanced oil recovery increases the oil recovery by up to 15%. Enhanced oil recovery methods, can be divided into three main categories: Thermal, Gas Injection and Chemical Injection. Figure 2.



***Figaro 2 - EOR methods (** *Maria Teresa 2016).*

They are mainly applied to extend the production life of an otherwise depleted or uneconomic reservoir by modifying fluid-fluid and fluid-rock properties consequently:

1- Thermal EOR: it is the most widely used method and mainly applied for heavy and extra heavy oil as it affects oil viscosity by heating it up.

2- Gas Injection: subdivided into miscible and immiscible flooding implies the injection of gases (hydrocarbons, carbon dioxide, nitrogen etc) to reduce oil viscosity, interfacial tension and increase oil swelling.

3- Chemical EOR includes the techniques that require injection in the reservoir of a mixture composed of chemical additives and water in order to improve sweep and microscopic efficiency.

EOR methods have presented interest since early 90s while many research and field application have been done in that times with concern to this. In latest times, until the volatility of oil prices hit the industry in 2014, a renew focus and increase of EOR deployment has been observed in many regions of the work, especially in the US and Canada. A forecast of IEA from 2012 depicts that by 2035, EOR production will represent approximately 25% of total world oil production.

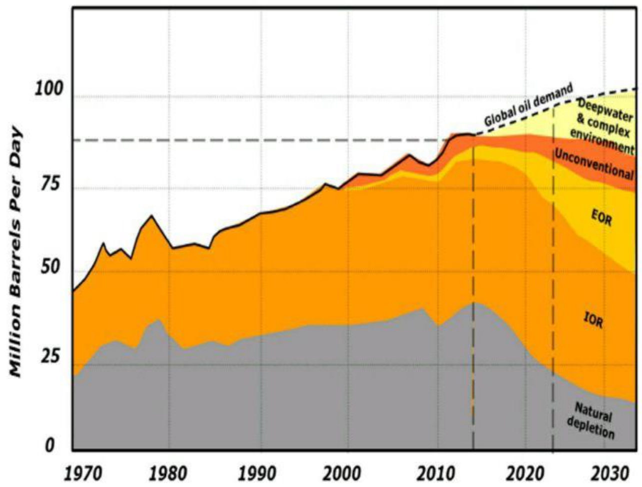


Figure 3- Worldwide Future Oil Production and Demand*(Maria Teresa 2016)*

The success of an EOR process can be assessed from both technical and economical point of view. Focusing on the technical part, the success is given by the incremental of oil recovered compared to primary or to secondary recovery as the oil production should deviate from the declined rate forecasted before. If on a simulation basis, to assess the gain in oil production is considered to be relatively easy as it can be resumed to the comparison of two cases, on a field application basis thing become more complex.

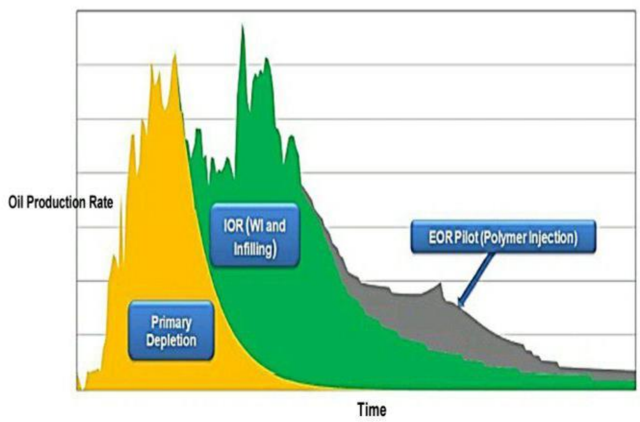


***Figure 4: Incremental oil for EOR. Adapted from* (Maria Teresa) 2016.**

In this study, we focus on finding new ways to increase the life of field production and evaluating the performance of the existing appropriate method through polymer injection.

IV.I. Thermal methods

During the thermal recovery the reservoir is heated to reduce oil viscosity. Thermal EOR is the most popular method accounting for more than 50% of the overall EOR market. Steam injection is the most common method used in thermal EOR. Other methods include in-situ combustion, where the reservoir is heated and an injected high-oxygen gas mixture burns to create a combustion front. Steam injection is mostly used in shallow reservoirs that contain high viscosity (usually heavy) crude oil. These include reservoirs in the San Joaquin Valley of California or those that comprise the oil sands of Alberta, Canada. Steam injection is a very well understood EOR method, used commercially since the 1960s. The injection of steam lets heat the crude oil in the formation thus lowering its viscosity and vaporizing some of the oil to increase its mobility. The decreased viscosity helps reduce the surface tension, increase the permeability of oil and improve the reservoir seepage conditions. Oil vaporization allows oil to flow more freely through the reservoir and to form better oil once it has condensed.

IV.1.1. Cyclic Steam Stimulation

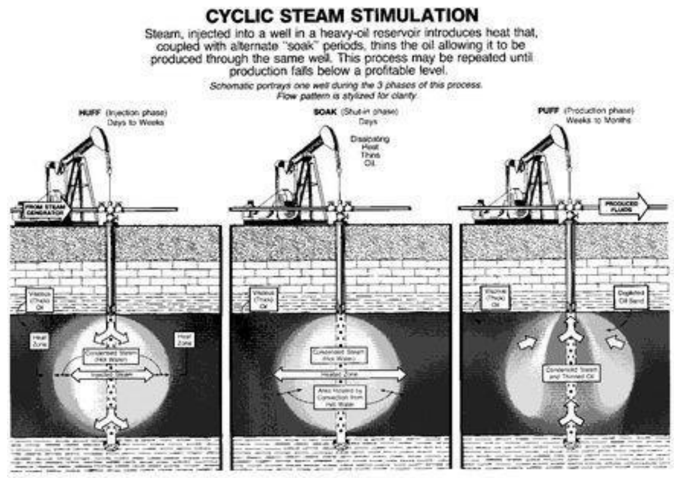


Figure 5- cyclic steam stimulation [23]

In cyclic steam stimulation (CSS), steam is injected into a production well for a period. Then the well is shut in and allowed to soak by steam for some period before it returns to production. The initial oil rate is high because of high initial oil saturation, high increased reservoir pressure, and lowered oil viscosity. As the oil saturation becomes lower, the reservoir pressure becomes lower and the oil viscosity becomes higher due to heat losses to the surrounding rock and fluids, oil rate declines. At some point, another cycle of steam injection is initiated. Such cycle may be repeated several times or many times. The terms of steam soak and steam huff-and-puff (huff-n-puff, huff 'n| puff) are also used to describe CSS. In this chapter, we will first briefly discuss CSS mechanisms, theories to estimate production performance, and screening criteria. After that we will focus on practice and field cases of CSS project.

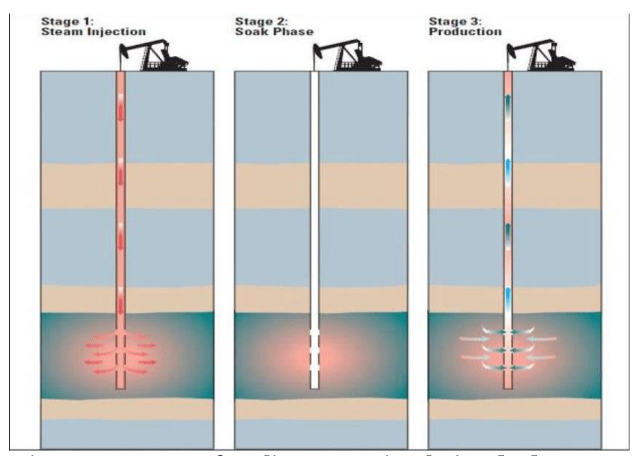


Figure 6 - steps of cyclic steam stimulation [22]

One-time-operated steam generators or heat recovery steam generators associated with cogeneration facilities are injected into the borehole in the target formation at temperatures of about 300°C and pressures averaging 11,000 kPa. This pressure is sufficient to cause the formation of unconsolidated oil sands to separate, creating paths for fluid flow. For each individual well, evaporation periods are followed by periods of soaking and then periods of production. CSS is a three-stage process: first, high-pressure steam is injected through a vertical well bore for a period of time; secondly, the tank is closed for soaking; And thirdly, the well is put into production. Typical initial cycle times for Imperial Cold Lake development are as follows: (1) injection, 4-6 weeks; (2) soak, 4-8 weeks; and (3) 3-6 months of production. When production rates drop, another cycle of steam injection begins. The injection and production cycle is repeated many times over the life of the well. Steam and well production time varies from well to well with each cycle, usually between 6 and 18 months. Expected recovery factors are between about 20% and 25% of the original bitumen in place. The number of steam catalysis cycles should be economical (6-7 times) and not more than 10 times. While the maximum production rate is observed in the second and third cycles. It is also recommended that when the rate of oil production reaches one third of the initial value at the beginning of the cycle, the cycle should be terminated and the next cycle started; In fact, this is highly suggested to keep the course performance high enough. Cyclic steam stimulation (CSS) has been used to recover heavy oil in California since the 1950s. CSS is often colloquially called a "huff-and-puff" operation. In this method, steam is injected into the well at a high temperature (572 to 644 degrees Fahrenheit (300 to 340 degrees Celsius)) for an extended period of time (usually weeks or months). The well is soaked with steam for some time (days to weeks) in order to liquefy the bitumen, and eventually hot bitumen (or additional heavy oil) is pumped out of the well. When oil production decreases, the cycle repeats. The CSS method may recover 20-25% of the oil in the formation, but the cost of steam injection is high. During the process, the tank temperature varies between the steam temperature (at the point of injection) and the tank temperature (at the point of production). The thermal expansion of the equipment, which occurs when steam is injected, is a big problem, so materials with suitable thermal expansion properties are selected for steam injection processes. The temperature in producing wells is lower than that in injection wells, so thermal expansion is not a problem. Production wells are subject to erosion because the effluent steam produces excess sand. Critical areas of equipment are often difficult to control for water. In general, the process can be very effective, especially in the first few cycles. Stimulating the well through the blowing process greatly improves the oil rate through three means:

1-Removal of asphalt and/or paraffin deposits accumulated around the wellbore, resulting in improved.

2- Permeability around the wellbore (ie preferred skin factor)

3-Radically reducing oil viscosity, which in turn improves oil mobility and well productivity.

4-Increasing the thermal expansion of the oil, which affects the oil's saturation and relative permeability. Injection volume and production time vary greatly from well to well and cycle to cycle. Steam-slug volumes varied from 204 to 904 bbl/ft net pay in the first cycle, from 291 to 881 bbl/ft net pay in the second cycle, and from 229 to 242 bbl of cold water equivalent vapor (CWE) per foot of net pay in The third session. The production period ranged from 215 to 946 days in the first cycle, from 246 to 749 days in the second cycle, and from 427 to 649 days in the third. Water retention varied from -246 to 68%, and the resulting factor ranged between 0.08 and 0.42 for the entire period of the first cycle. Since the production phase was long, water retention and productive work were calculated for the first 200 days of production keeping in mind that the production phase should be around 200 days per cycle. The water retention ranged from 27 to 74%, and the value of the work produced ranged between 0.13 and 0.74 in the first 200 days of production. The resulting water contained condensed vapor and some formation water. Water retention is calculated by this relationship: % water retention = (CWE vapor injection − water produced) x 100/CWE steam injected.

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V. Objective

1- The objective of this report is to provide basic technical information regarding the cyclic steam simulation enhanced recovery reservoir process, which is at the core of the evaluation methodology, for the determination of technically recoverable oil.

2- Knowledge of enhanced recovery reservoir mechanisms using cyclic steam simulation.

3- What are the most suitable and capable reservoirs for cyclic steam simulation enhanced recovery reservoir applications.

4- Know when and where enhanced recovery reservoir with cyclic steam simulation succeeds or fails.

5- Understand software that can simulate the enhanced recovery reservoir using cyclic steam simulation.

6- Knowing the effects and negatives of cyclic steam simulation on the enhanced recovery reservoir.

7- See criteria screening for past cyclic steam simulation for Enhanced oil recovery.

VI. Cyclic Steam Stimulation

Injection, Steam Soaked, Huff and Puff: In cyclic steam stimulation the same well is used for steam injection and oil production. At first, steam is injected for a period from couple of weeks to a couple of months. The introduced steam allows heat up the oil immediately surrounding the injection well through convective heating thus lowering its viscosity (Fig4-3-left). After the target viscosity is reached, steam injection stops to allow heat to redistribute evenly in the formation. This helps maximize the amount of oil recovered after this stage. The well can then be produced until the temperature in the well drops and the viscosity of oil increases again (Fig. 1-right). This cycle is repeated until the response becomes insignificant and economical limits are reached. Obviously, most of the oil is produced in the first few cycles.

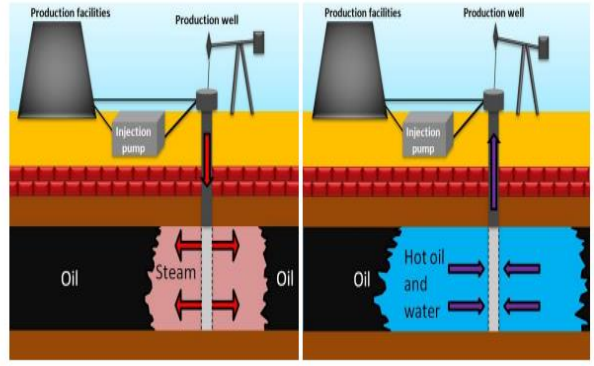


Figure 7- Cyclic steam stimulation. Left: Steam injection. Right: Production (G. Zerkalov)2016.

Table 3 - proper parameters to apply cycle system simulation project (NIOC)2016.

Parameter	Desirable extent	Parameter confine in running projects
Oil API degree	10-27	8-27
Viscosity (CP)	<50000	500-1000
Oil compound	Some asphaltic components to aid coke deposition	
Oil saturation degree (pv %)	>60	55-90
Reservoir rock type	Sand or Sandstone with high porosity but it is possible in carbonate reservoirs	
Net Thickness(ft)	>10	
Permeability degree (md)	>100	63-10000
Transmissibility md-ft/cp	>20	
Depth (ft)	>500	1000-4500
Temperature (f°)	>150	60-280

VI.I. MECHANISMS

The first mechanism of CSS is the reduced oil viscosity owing to the steam injection. Steam injection increased the reservoir pressure. Thus the pressure drop is high. According to the Darcy equation, the oil rate is increased. Figure 8 is a schematic of a radial flow model after steam stimulation. Let us use the steady-state Darcy flow equation. The production rate at the downhole conditions after steam stimulation, q_{oh}, is:

$$\frac{J_h}{J_c} = \frac{\log(r_e/r_d) + k/k_d \log(r_d/r_w)}{\log(r_e/r_h) + (\mu_{oh}/\mu_{oc})\log(r_h/r_d) + (\mu_{oh}/\mu_{oc})\log(r_d/r_w)}$$
$$= \frac{\log(500/5) + (10)\log(5/0.25)}{\log(500/50) + (0.01)\log(50/5) + (0.01)\log(5/0.25)} \quad (1)$$
$$= 14.7$$

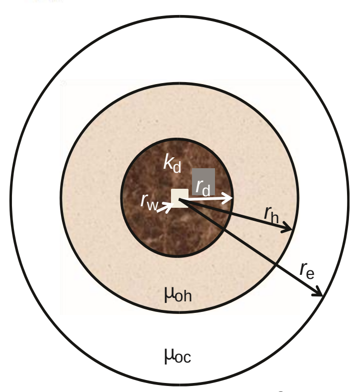


Figure .8. Schematic of a radial flow model after steam stimulation.(James. G) 2013.

The production rate before steam stimulation, q_{oc}, is:

$$q_{oc} = \frac{2\pi h(p_e - p_w)}{\frac{\mu_{oc}\ln(r_e/r_d)}{k} + \frac{\mu_{oc}\ln(r_d/r_w)}{k_d}} = \frac{2\pi k k_d h(p_e - p_w)}{k_d \mu_{oc}\ln(r_e/r_d) + k\mu_{oc}\ln(r_d/r_w)} \quad (2)$$

The ratio of production index after steam stimulation (Jh) to that before (Jc) is:

$$\frac{J_h}{J_c} = \frac{k_d\mu_{oc}\ln(r_e/r_d) + k\mu_{oc}\ln(r_d/r_w)}{k_d\mu_{oc}\ln(r_e/r_h) + k_d\mu_{oh}\ln(r_h/r_d) + k\mu_{oh}\ln(r_d/r_w)}$$
$$= \frac{(k_d/k)\ln(r_e/r_d) + \ln(r_d/r_w)}{(k_d/k)\ln(r_e/r_h) + (k_d/k)(\mu_{oh}/\mu_{oc})\ln(r_h/r_d) + (\mu_{oh}/\mu_{oc})\ln(r_d/r_w)} \quad (3)$$

Assume a practical case: $r_e = 500$ ft, $r_h = 50$ ft, $r_d = 5$ ft, $r_w = 0.25$ ft, $k_d/k = 0.1$, and $\mu_{oh}/\mu_{oc} = 0.01$. Then

$$\frac{J_h}{J_c} = \frac{(k_d/k)\log(r_e/r_d) + \log(r_d/r_w)}{(k_d/k)\log(r_e/r_h) + (k_d/k)(\mu_{oh}/\mu_{oc})\log(r_h/r_d) + (\mu_{oh}/\mu_{oc})\log(r_d/r_w)}$$
$$= \frac{(0.1)\log(500/5) + \log(5/0.25)}{(0.1)\log(500/50) + (0.1)(0.01)\log(50/5) + (0.01)\log(5/0.25)} = 12.2$$

In other words, the productivity is increased by 12.2 times after stimulation when the damage is not removed by steam (k_d is unchanged). When the damage is removed by steam (k_d is equal to k after stimulation), the productivity is increased by:

This example calculation shows that the productivity is increased by a similar magnitude whether the formation damage is

Removed or not by steam injection. It is implied that the main mechanism of cyclic steam injection is the reduction in oil viscosity. Although removing damage does improve productivity, the improvement is much less (by 20% in this example) than that by viscosity reduction. However, if the steam injection has removed the formation damage and the reservoir has been cooled, the improvement in the productivity is significantly improved. For this example, the improvement is:

$$q_{oh} = \frac{2\pi h(p_e - p_w)}{\dfrac{\mu_{oc}\ln(r_e/r_h)}{k} + \dfrac{\mu_{oh}\ln(r_h/r_d)}{k} + \dfrac{\mu_{oh}\ln(r_d/r_w)}{k_d}}$$
$$= \frac{2\pi k k_d h(p_e - p_w)}{k_d\mu_{oc}\ln(r_e/r_h) + k_d\mu_{oh}\ln(r_h/r_d) + k\mu_{oh}\ln(r_d/r_w)} \quad (4)$$

This example calculation shows that the mechanism of steam stimulation to remove formation damage near the production well will be in effect after the reservoir cools down. This is the second mechanism. The formation damage could be caused by deposition of solids, paraffin, or asphaltene near the production well. The third mechanism may be explained by this situation. When the oil viscosity is very high, or the well spacing is too large, an unrealistically high injection pressure is needed in steam flooding. In such situation, CSS may work by heating a small zone and using a lower injection pressure. In fact, CSS is a precursor to steam flooding in most reservoirs. Other mechanisms may include fluid expansion and rock compaction (de Haan and van Lookeren, 1969), gravity drainage, relative permeability modification, wettability alteration, distillation, and interfacial tension reduction. Rock compaction was observed to be significant in some cases.

VI.II. **ESTIMATING PRODUCTION RESPONSE FROM CSS-BOBERG AND LANTZ MODEL**

We use the Marx and Langenheim (1959) model to compute the radius of heated zone as the steam is injected into a reservoir.

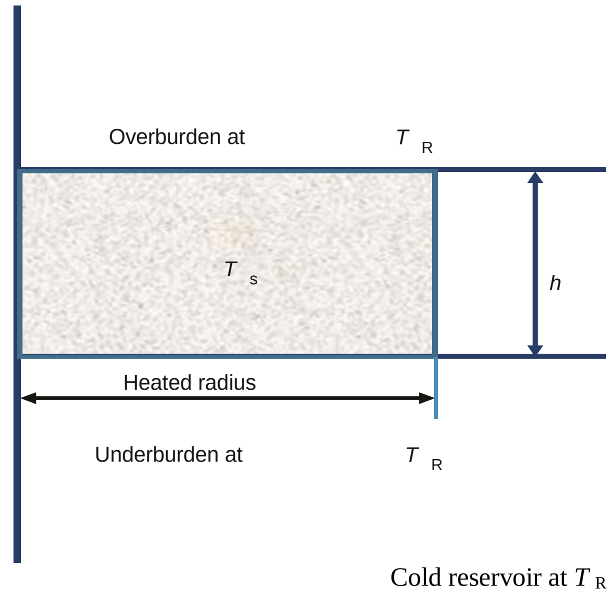


FIGURE.9. Initial reservoir temperature distribution in the Boberg and Lantz model. ***(James. G) 2013***

When the steam injection stopped and the well is put in production, the reservoir temperature will decrease owing to the heat loss to the overburden and underburden rocks and the heat loss by produced fluids. This decrease in the average temperature of the reservoir is computed in the Boberg and Lantz (1966) model. Although the heat loss to the overburden and underburden is considered to compute the radius of the heated reservoir in the Marx and Langenheim model, the temperatures outside the heated zone are treated to maintain at the initial reservoir temperature T_R before steam injection. Therefore, the initial temperatures outside the heated zone in the Boberg and Lantz model will also be at T_R, as shown in Figure .9. During the shut-in and production periods, the heat losses by conduction in the vertical and horizontal direction are

$$\frac{J_{\text{after ccs}}}{J_{\text{before ccs}}} = \frac{\log(r_e/r_d)/k + \log(r_d/r_w)/k_d}{\log(r_e/r_d)/k + \log(r_d/r_w)/k}$$
$$= \frac{\log(500/5) + \log(5/0.25)(10)}{\log(500/5) + \log(5/0.25)}$$
$$= 4.55$$

considered. Although the colder fluids enter the heated zone, the average temperature model does not explicitly account for this effect.

The differential equation used in the mode is:

$$\frac{k_h}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right) + k_h\frac{\partial^2 T}{\partial z^2} = M_R\frac{\partial T}{\partial t} \quad (5)$$

Where M_R is the average heat capacity of the overburden or underburden rock and the reservoir, and k_h is the thermal conductivity coefficient. The initial and boundary conditions are shown in Figures 9 and.10, respectively. This model considers the heat loss to the overburden and underburden rocks by conduction only.

The solution is presented in dimensionless quantities:

$$\overline{T}_D = \overline{T}_{Dr}\overline{T}_{Dz} \quad (6)$$

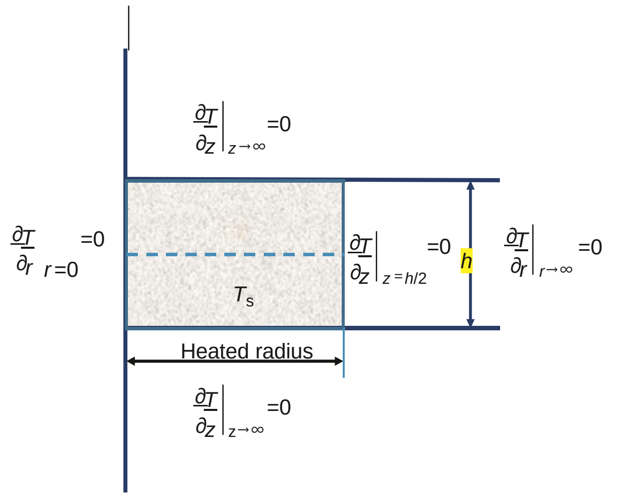


FIGURE .10. Boundary conditions in the Boberg and Lantz model. (James. G) 2013

Where:

$$\overline{T}_D = \frac{\overline{T} - T_R}{T_s - T_R} \quad (7)$$

T_{Dr} and T_{Dz} are the components of T_D in the r and z directions, respectively. They may be found from a chart presented by Boberg and Lantz (1966) or calculated using the following equations: The expanded form of Eq. (9) is:

For $0.01 < t_{Dr} \le 0.1$ (G. Paul Willhite, January 9, 2012, communication),

$$\overline{T}_{Dr} = 1 - \sqrt{\frac{t_{Dr}}{\pi}}\left(2 - \frac{t_{Dr}}{2} - \frac{3}{16}t_{Dr}^2 - \frac{15}{64}t_{Dr}^3 - \frac{525}{1024}t_{Dr}^4 - \cdots\right) \quad (8)$$

The above expansion only gives approximate values as t_{Dr} smaller.

For $t_{Dr} > 0.05$,

$$\overline{T}_{Dr} = \frac{1}{4t_{Dr}}\left[1 - \frac{1}{4t_{Dr}} + \sum_{k=2}^{\infty} s_k\right] \quad (9)$$

where

$$s_1 = 1/4$$

$$s_k = \left[\left(-\frac{1}{t_{Dr}}\right)\frac{(0.5+k)}{(1+k)(2+k)}\right]s_{k-1} \quad (10)$$

$$\overline{T}_{Dr} = \left(\frac{1}{4t_{Dr}} - \frac{1}{16t_{Dr}^2} + \frac{5}{384t_{Dr}^3} - \frac{1}{439t_{Dr}^4} + \frac{7}{20480t_{Dr}^5} + \cdots\right) \quad (11)$$

It turns out that the series expansion is a fairly accurate representation of the average radial temperature for t_{Dr}.0.05 but requires a number of additional terms for small t_{Dr}. It is necessary to continue the series until the last value is on the order of 10^{25}.

Although Boberg and Lantz did not place a restriction on this solution, Bentsen and Donohue (1969) added the restriction of t_{Dr}.10.

T_{Dz} is calculated from (Bentsen and Donohue, 1969)

$$\overline{T}_{Dz} = \mathrm{erf}\left(1/\sqrt{t_{Dz}}\right) - \left(\sqrt{t_{Dz}/\pi}\right)\left(1 - \exp(-1/t_{Dz})\right) \quad (12)$$

In these equations, t_{Dr} and t_{Dz} are defined as

$$t_{Dr} = \frac{\alpha(t - t_i)}{r_h^2} \quad (13)$$

$$t_{Dz} = \frac{\alpha(t - t_i)}{(h/2)^2} \quad (14)$$

Where t_i is the initial time and α ($5k_h/M_R$) is the thermal diffusivity.In the above formulation, the initial temperature outside the heated zone is assumed to be the cold reservoir temperature T_R. In reality, there is a temperature gradient from the heated zone to the outside. To consider this temperature gradient, a hypothetical thickness Δh is added in the actual reservoir thickness h in Eq. (14). Δh can be estimated from the overall energy balance:

$$m_s h_s = \pi r_h^2 M_R (T_s - T_R)(h + \Delta h) \quad (15)$$

In the above formulation, the heat loss from the produced fluids is not included. To include this heat loss, a correction factor δ is added in Eq. (16). Thus the average pressure in the heated zone is calculated from:

$$\overline{T}_D = \overline{T}_{Dr}\overline{T}_{Dz}(1 - \delta) - \delta \quad (16)$$

where δ is defined by

$$\delta = \frac{1}{2}\frac{\int_{t_i}^{t_p}\dot{Q}_p\,dt}{Q_i} = \frac{1}{2}\int_{t_i}^{t_p}\frac{\dot{Q}_p\,dt}{\pi r_h^2 h M_R (T_s - T_R)} \quad (17)$$

Where Q_i is the total heat at the initial time t_i, t_p is the production time which is measured from the termination of steam injection, and Q_p is the rate of produced heat. Equation (16) is an empirical equation proposed by Boberg and Lantz (1966). Note when δ is equal to $^1/_2$, T_D may be negative, according to Eq. (16). In this case, T_D is forced to be zero.

The rate of produced heat Q_p at the downhole condition is related to the production rates and average temperature of the heated zone by:

$$\dot{Q}_p = \left(q_o M_o + q_w M_w + q_g M_g + q_s M_w + \frac{q_s \rho_w L_v}{T_s - T_R}\right)(T_s - T_R) \quad (18)$$

Note that all these rates are at downhole conditions, q_s is the steam injection rate in the cold water equivalent (CWE). Downhole oil and gas rates are not difficult to estimate from surface one. But the water and steam production rates must be corrected from that measured at the surface to account for heat losses. If the calculation is made in time steps, these rates are the average rates in the time intervals. Be careful that consistent units must be used. Several other analytical models are available for the CSS process (Clossmann et al., 1970; de Haan and van Lookeren, 1969; Martin, 1967 ; Seba and Perry, 1969). From the description of the Boberg and Lantz model, we can see that the hand calculation is tedious and many assumptions are made in the model. In modern days, numerical simulators are much easier to handle such calculation.

VI.III. SCREENING CRITERIA

Taber et al. (1997) and Green and Willhite (1998) summarized the general screening criteria without differentiating steam flooding and steam soak. In fact, the ranges of parameters used in actual field steam soak projects are wider than the ranges presented by these two groups. In other words, the applicable conditions for steam soak are less restrictive than for steam flooding. Table .4 summarizes our modified criteria for the steam soak process.

Table 4 . Screening Criteria and Average Field Data(James. G) 2013

Parameters	Criteria Values	Design Criteria	Average Field Data
Oil gravity, °API	8–35	<15	14.4
In situ oil viscosity, cP	50–350,000	4000	5247
Oil saturation, fraction	>0.4		
Net thickness, m	>6	>9	24.2
Net/gross ratio, fraction	>0.4		
Porosity (ϕ), fraction	>0.18	≥0.35	0.32
Permeability, mD	>50	≥1000	1736
Transmissibility, mD-ft/cP	>5		
Depth, m	<1525	<915	518
Gas cap	Not desirable		
Aquifer	Not desirable		
Fracture	No		
Clay	Low		
Steam quality, %		80–85	
Steam pressure, psig		~1500	900
Injection time, days		14–21	11
Soak time, days		1–4	6.25
Number of cycles		3–5	3
Cycle length, months		~6	~6

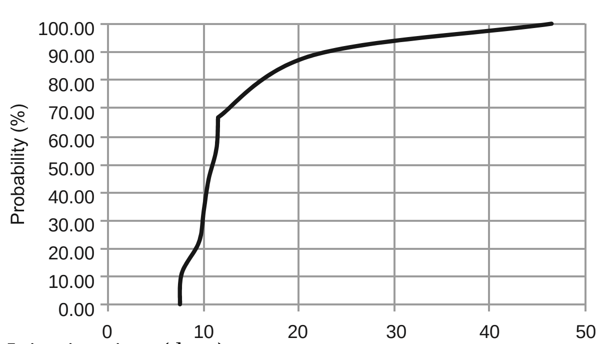
by including the parameters used in field practices. The design criteria summarized by Farouq Ali (1974) are also listed in this table. Under these design criteria, some of field projects have been successful. Based on our survey data on Chinese field projects (unpublished) and the survey data reported by Farouq Ali (1974) and Farouq Ali and Meldau (1979), we did statistical data analysis (rank and percentile) for some of parameters. Some of the average data for the surveyed field projects are presented in Table .4. The field data were at 50% probability for the survey data. Performance data will be presented in figures in the next section. When the measured temperature was not the same as the reservoir temperature, the oil viscosity is interpolated or extrapolated assuming that 10C increase would result in the decrease in oil viscosity by half. When a range of viscosities were reported, the middle point viscosity is picked. For any other parameter, when a range of values are provided, a simple arithmetic average value is used in the statistical analysis. The gross thickness is also an important parameter. Unfortunately, enough data were not collected to do the analysis. Generally, a gas cap or a bottom aquifer is not desirable because the former will promote the gravity override of steam, and a large aquifer will serve as a heat sink. In such a reservoir, optimized well placement and development plan are needed, as was done in the Gaosheng field case presented later in this chapter. The values of other screening parameters are listed but not discussed here.

VI.IV. PRACTICE IN CSS PROJECTS

Some of the design criteria are summarized by Farouq Ali (1974) and presented in Table 4. The practice presented in this section may also serve as references for design criteria.

VI.IV.I. General Producing Methods

If reservoir oil viscosity is 50150 mPas, water flooding is carried out first followed by steam flooding. If the viscosity is 15010,000 mPas, steam flooding is directly applied because water flooding may not be effective. CSS followed by steam flooding will be more effective. When the reservoir oil viscosity is 10,00050,000 mPas, CSS is needed. Subsequent steam flooding is carried out if favorable reservoir conditions are met. When the oil viscosity is above 50,000 mPas, special production techniques are needed, such as fracturing, horizontal wells, and adding chemicals. For a multilayer reservoir, the steam injection should be started from the bottom layer and moved up so that the top layers are preheated. At a proper time, steam soak is converted to steam flooding.



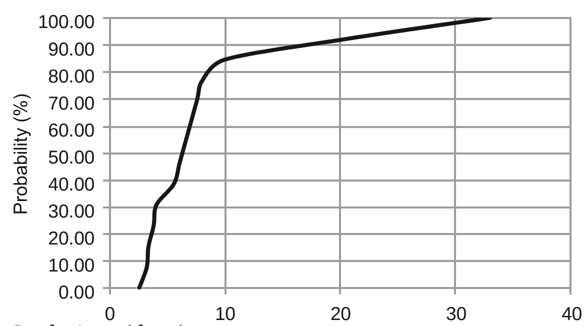
Injection time (days)

FIGURE.11. Injection time in actual CSS projects. (James. G) 2013.

For a reservoir with gas cap or edge or bottom aquifer, the pressure balance is controlled between the oil zone and water or gas zone. Well completion intervals need to be optimized. Wells should be drilled in the oil zone first and then expanded toward the edge water zone. In the existence of bottom aquifer, perforation should be above the water zone, e.g., 15 m in the Shu 175 block. Liu (1997) investigated the conditions under which a heavy oil reservoir can be economically developed by CSS using simulation approach. He assumed that oil viscosity, reservoir thickness, and depth are the main parameters which determine the steam soak performance and did sensitivity studies on these parameters.

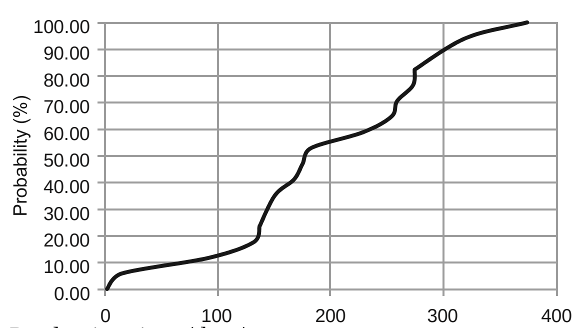
VI.IV.II Injection and Production

Parameters Steam injection period could be a few days to a few weeks. Figure .11 shows the injection time from actual field projects. The data sources are the same as those in Table .4. The average injection time at the 50% probability is 11 days. If soak time is too short, more heat is accumulated near the wellbore and will be produced when the well is open. If soak time is too long, heat loss to overburden and under burden will be high and the production time becomes longer. However, if the reservoir has sufficient pressure, a long soak period may be desirable in order to increase the thermal efficiency of the process (Farouq Ali, 1974). Adams and Khan (1969) found an optimum soak time of 9 days based on a correlation of six months' cumulative oil production versus soak time. The field data show an average soak time of 6.25 days as shown in Figure .12. Liu (1997) observed that 23 days of soak time should be enough. The average production time is 180 days (about half a year) as shown in Figure .13.



Soak time (days)

FIGURE .12 Soak time in actual CSS projects. (James. G) 2013.



Production time (days)

FIGURE .13.Production time in actual CSS projects. (James. G) 2013.

Figure .14 shows the well total injection per cycle (CWE) from actual field projects with the average of 10,800 bbls of CWE. The average injection pressure is 900 psi, as shown in Figure .15. The amount of steam injection is typically 80160 tons/m of oil column, with the higher side for thinner reservoir and the lower side for a thicker reservoir. The amount of steam injected increases with the cycle number by 1015% (Liu, 1997).

When we discussed the CSS mechanism, we mentioned that one mechanism is to reduce formation damage. This is achieved by cleanup during backflow period. From this point of view, the amount of steam injected in the first cycle should not be too high, because a high volume of steam may displace the plugging materials far away from the wellbore, and then it will be more difficult for the plugging materials to be flushed back. In a very high viscous reservoir, generally the performance in the second and third cycles is better than that in the first cycle. From this point of view as well, the amount of steam injected should not be too high in the first cycle, but the steam should have a high quality.

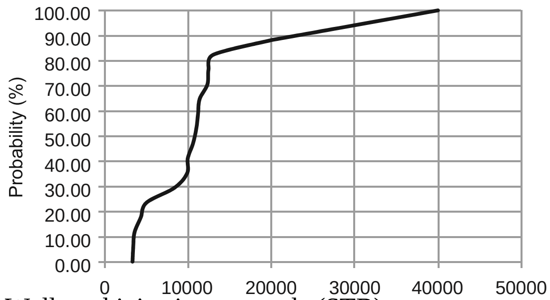


FIGURE .14 Well total injection rate per cycle** (**James. G**)* ***2013..

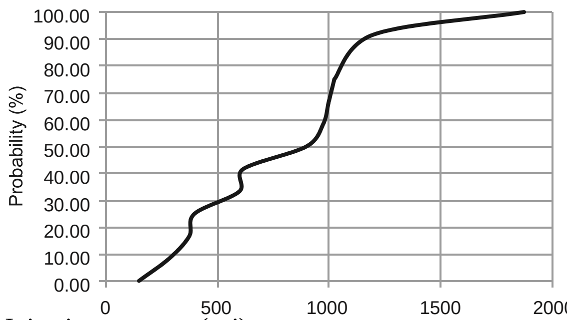
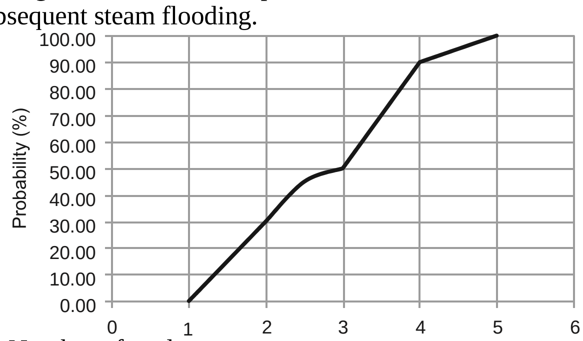


FIGURE .15. Well injection pressure.** (**James. G**) **2013.

CSS is mature even at deep reservoirs (e.g., 1700 m). The number of steam stimulation cycles which are economical and effective is 67 and should not be greater than 10 (Liu, 1997). Generally, the peak oil rates are in the second and third cycles and decrease sharply during the fourth to sixth cycles. After the seventh cycle, oil rate decreases slowly. On average, three stimulation cycles have been used, as shown in Figure 16. The data are from Farouq Ali (1974). To make the heat more efficient, development should be made area by area for steam soak, although steam soak is conducted in single wells. When the oil rate is about one-third of the rate at the beginning of the cycle, the next cycle of steam injection should be started. In other words, switching to next cycle should be made when the pressure is high and rate is high. Otherwise, the performance of the subsequent cycles will be deteriorated. Liu (1997) suggested that all the wells should be drilled based on a designed well spacing, instead of drilling infill wells at a later time. This will avoid formation damage and sand production caused by infill drilling when the reservoir pressure is low. It will also help the subsequent steam flooding.



FIGUR E .16.Number of cycles in actual CSS projects. (James. G) 2013.

VI.IV.III. Completion Interval

Similar to steam flooding process, wells should generally be completed in the bottom half of the oil layer. If there is a bottom aquifer, the completion should be away from the aquifer for some distance. In a steam soak process, completion in the bottom part may help improve the subsequent steam flood performance.

VI.IV.IV. Wellbore Heat Insulation

For the reservoir depth of 300400 m, ordinary tubing can be used with packers and nitrogen filled in the annulus. If the depth is above 400 m, insulated tubing and heat-resistant packers are needed. If the depth is 8001600 m, high-quality insulated tubing and packers must be used with nitrogen filled in the annulus.

VI.IV.V. Incremental Oil Recovery and OSR

Figures.17 and.18 show the statistical analysis of actual field data for incremental oil recovered per well and oil-steam-ratio (OSR). The incremental oil recovery and OSR at the 50% probability are 8775 bbls and 0.43 , respectively. 5.6 Monitoring and Surveillance During steam injection, injection wellhead temperature, pressure, steam quality, and injection rate are measured. The steam quality at the exit of a boiler and at wellbore should be higher than 75% and 40%, respectively. During soak period, pressure and temperature are monitored. During production, production rate, wellhead pressure, casing pressure, and the temperature of produced fluid are measured. The water cut and temperature are monitored.

The dynamic liquid level is measured once a week in the beginning.

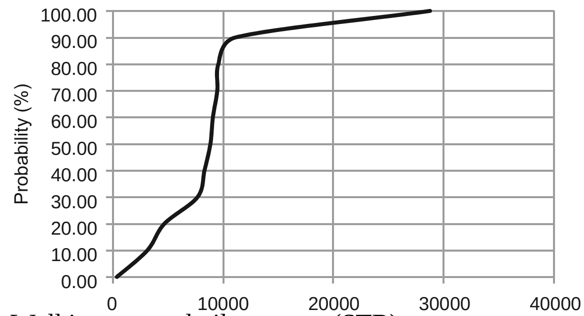


FIGURE 17. Incremental oil recovery per well in actual CSS projects.** (**James. G**) **2013.

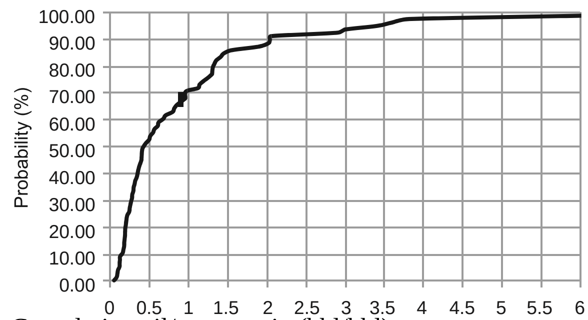


FIGURE 18. Cumulative OSR in actual CSS projects.

Fluid samples are taken and analyzed for 30% wells in the first cycle and 15% wells in the second cycle. Water cut, sand content, and chloride ion content are monitored (Zhang, 2006).

VI.V. FIELD CASES

Seven field cases are presented which include Cold Lake in Alberta, Canada, Midway Sunset in California, Du 66 block in the Liaohe Shuguang field, Jin 45 Block in the Liaohe Huanxiling field, Gudao Field, Blocks 97 and 98 in the Karamay field, and Gaosheng Field in China.

Table 5. Cyclic steam stimulation 2022.

	field name	API	viscous oil	temperature	depth	porosity	permeability	thicknes	pressure
1	ColdLakeinAlberta,Canada	10.2	100000	13 c	300 to 600 m	37%	3000md	33m	450
2	MidwaySunsetinCalifornia	11.5 to 13							
3	Du66BlockintheLiaoShuguangField,China		300-2000 mPa	47-54 C	800-1200 m	25%	780mD	42.1m	9.69-11.04 mPa
4	Jin45BlockinLiaoheHuanxilingField,China		486-7696 mPa	44.6-50 C	890-1180 m	29%	800 mD		10mPa
5	GudaoField,China		5000-24,562mPa	50 c	1300 m.	30-35%	770-2000 mD		
6	Blocks97and98inKaramayField,China		350,000mPa	20 C		30.60%	1287 mD,	70- 150 m	
7	GaoshengField,China		74-605 mPa	60 C	1500-1800 m.	22-26%	1000-2300 mD	67.7m	16.1mPa

1. Cold Lake in Alberta, Canada

This was the largest CSS project in oil sands. Cold Lake was one of the four major Alberta oil sands deposits. It contained an estimated 160 billion barrels of low gravity (10.2API) and highly viscous oil (100,000 mPas at 13C reservoir temperature). The reservoir depth was from 300 to 600 m. Therefore, the oil was too deep to be produced by surface mining or too viscous to be pumped at a reasonable rate at original conditions. The formation porosity was 37% and the permeability was 3000 mD.

The reservoir thicknesses were on the order of 33 m. Esso Resources Canada began laboratory and engineering studies in the early 1960s, progressing to small-scale field pilots in 1964. In order to provide a sound planning base for future operations, an evaluation program of drilling and coring was started in 1973 (Buckles, 1979). Because Cold Lake oil (bitumen) at reservoir conditions (450 psi and 13C) was practically immobile, it was necessary to stress the formation to the point of yielding for steam injection. It was found that the Clearwater formation of main interest would yield to a downhole pressure of 1300 psi. The initial breakdown pressure might be 3050% higher. With high injection pressure, vertical and horizontal fractures were generated to accommodate large volumes of hot fluids. The Ethel pilots were initiated in late 1964 and operated until 1970. The stimulation wells were completed in the Clearwater bitumen zone and were stimulated through eight cycles. The size of steam treatments ranged from 3000 to 5000 bbl. Gas was injected with steam in seven of the cycles, and air and water with steam were injected in two cycles. These additives were not convinced to be beneficial. A soak period of about 5 days was unusually allowed for heat dissipation in the reservoir. The well was then opened for production for a few weeks which might continue for 58 months, depending on the fluid temperature and observed decline in oil rate. In October 1969, a bottom water 5-spot steam flood was initiated. The flood contained one central producer, four steam injectors, and four confining producers, all of which were open to the bottom water. The objective was to determine whether heating conformance in the oil zone could be improved by injecting steam into the more mobile lower water zone. The rate of vertical heating was found to be slow and the experiment was terminated in April 1970. Steam generation and fluid handling facilities were upscaled to the commercial scale, based on the pilot tests and engineering studies: 20% bitumen recovery, well production rate of 80 bbl/day over an average of 6 year life, and 0.4 OSR.

2. Midway Sunset in California

This case is about sequential steaming process in the Midway-Sunset field. According to the sequential steaming process, wells would be steamed in rows, on strike, sequencing from down- to updip. To take advantage of the theoretical and observed benefits of asynchronous steaming, a row would be steamed in two stages of alternate, adjacent wells (Jones and Cawthon, 1990 ; McBean, 1972), as shown in Figure 19.

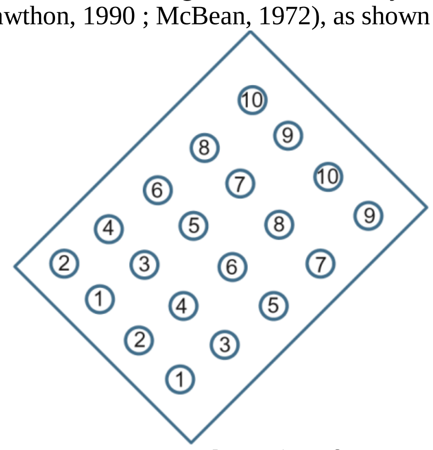


***FIGURE 19. Schematic of sequential well steaming process (the values of numbers indicate the sequence).** (James. G) 2013.*

The Potter sands were the primary producing zones in the northern end of the Midway-Sunset field. The sands were predominantly a series of fan-channel complexes formed during rapid subsidence of the basin. Coarse granitic debris from the coastal range flowed down marine canyons into a deepwater fan. The depositional character of the Potter is extremely variable, ranging from massive, conglomeritic, debris-flow-filled, narrow channels to thinly bedded, laterally extensive, very-fine-grained, distal-fan turbidites. The subsidence produced a generally transgressive sequence; i.e., the deeper-water, thinly bedded deposits tended to overlie stratigraphically the coarser, shallow-water channels. Subsequent uplift and tilting produced an erosional surface. The producing sands outcropped at the western limit of Potter and were covered by a rapidly thickening wedge of Tulare silts and sands toward the east. Dips ranged from about 40 at the west to 20 at the east and trended north to east.Common reservoir properties in these leases were low-gravity crude (11.513API), fairly steep dips, and high lateral permeability between well locations. Cyclic steam operations in the Midway-Sunset field began in early 1964. The first cycle experienced peak oil rates of nearly 200 B/D and convinced that steam was a very attractive EOR method in this reservoir. The first steam drive began in August 1967 in an up-structure attic location. Unfortunately, the project performed poorly. A post-audit of this drive showed conclusive evidence of uncontrolled steam loss to the up-structure air zone. Several steam drive projects in later years were not successful. CSS was tested in this field. More than 19,000 steam cycles were performed in 1500 wells in the Midway-Sunset field. Most of wells were Potter wells. More than 75 wells received 30 or more cycles, and more than 350 wells received 20 or more. The first cyclic well produced 10 bbl/day at the 39th cycle and with cyclic peaks in the 100 bbl/day range. With the much cyclic activity, a number of field tests were performed to optimize the cyclic steam process. Finally, it was found that the sequential steaming process to take advantage of gravity drainage is the process in this dip reservoir. Here is an example performance of sequential steaming process. In the 27 USL lease, a steady decline of 2% per year was arrested and reversed after implementing an infill drilling and sequential-steam program in 1980 and 1981. Well spacing was decreased from about in $1^1{}_4$ acre and $^5{}_8$ acre. A steam injection schedule was set up in the pattern shown in Figure 19 with steam rates increased from about 8000 to 12,000 bbl/ year per well. As a result, oil production increased from 15 to 24 bbl/day per well. The key thermal-efficiency indicator, OSR, remained between 0.53 and 0.83 bbl/bbl.

3. Du 66 Block in the Liao Shuguang Field, China

The Du 66 block was in the Liao Shuguang field. The block had many thin layers. It had an oil-bearing area of 4.9 km^2 with original oil in place (OOIP) of 39.4 million tonnes. The reservoir depth was 8001200 m. The average reservoir thickness was 42.1 m, average permeability 780 mD, and average porosity 25%. The reservoir had many think layers and about 30 clay interbeds. The average thickness of these interbeds was thicker than 3 mm. The net-to-gross ratio was low (,0.5). The oil viscosity was 3002000 mPas. The reservoir temperature was in the range of 4754C. The measured pressure was 9.6911.04 mPa. Cyclic steam injection was initiated at the well Shu-1-37-35 in March 1985. Steam was injected from March 16 to March 27 for 12 days. A total of 2302 tons of steam was injected. The well was under natural flow for 3 days. The average oil rate was 104 tons/day. Steam was injected again from April 5 to April 16, 1985. The total steam injection was 2554 tons. Then there was a steam soak for 2 days followed by 8 days of natural flow and 237.2 days of pumping. The cumulative OSR was 2.9. The steam injection was expanded in 1986. The injection patterns were in 200 m square patterns (5-spot patterns). By October 1989, a total of 187 wells had been drilled according to the development plan. Afterward, new wells were drilled to adjust the injection patterns. By February 1990, a total of 358 wells had been drilled including 200 producers, 138 injectors, and 20 observation wells. At a later time, infill wells were drilled. In September 1991, a steam flooding pilot was initiated. By December 1993, 343 wells had been drilled with 325 wells open. The total oil rate was 1496.4 tons/day, the water cut was 46.7%. The recovery factor was 9.64%. The cumulative OSR was 1.01. The cumulative oil production was 1.32.3 times that of the analog block, Du 84 block, where waterflooding was implemented.

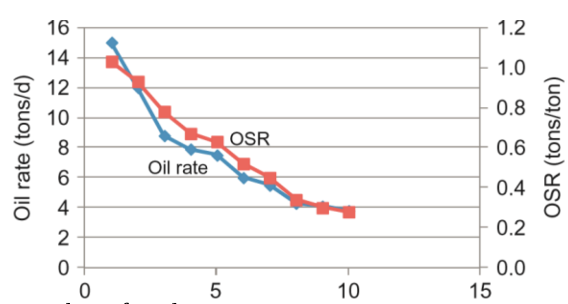


***FIGURE 20. Oil rates and OSR at different cycles.** (James. G) 2013.*

During 19941998, more infill wells were drilled. After 1998, no new wells were drilled. In the Du 166 and Du 97 well patterns, hot water was added in the steam stream. In the well Shu-1-45-31 well pattern, wateralternate-steam injection and hot water injection were tested. In June 2003, the Du 66 block had 538 wells with 428 wells open, 36 hot water or steam flooding wells with 24 wells open, and 10 observation wells. The water cut was 62.6%, the recovery factor was 19.76%, and the cumulative OSR was 0.64. The average oil rate was 1.5 tons/day. The average reservoir pressure was 1.2 mPa, significantly reduced compared with the initial reservoir pressure. The average cycles were 8. The initial oil rates per well and OSR in each cycle are shown in Figure 20. The oil rates and OSR decreased with the cycle. The Du 66 block was in the late stage of cyclic steam injection. The question was whether it should be converted to steam flooding. A simulation study of a pilot zone of four patterns showed that 55.14% recovery factor for steam flooding, 49.4% for intermittent steam injection (2-month injection and 1-month pause), and 49.8% for steam flooding for 4 years followed by cold waterflooding. The simulation results showed steam flooding should be continued. The subsequent pilot showed that injection profile needed to be improved before steam flooding. At the end, the main layers were under steam flooding.Several production techniques have been implemented. One was to use prestressed casing. Prestressed casings were installed in more than 250 wells. Casing was found damaged only at 1 well. Rods were heated electrically so that the oil in the wellbore was heated and the oil viscosity was reduced. Mixing produced oil with hot oil also reduced the oil viscosity. Several lessons from this block are (Liu, 1997):

a. Combine thin layers into several thick layers and selectively perforate thick layers.

b. Steam quality should be high in such reservoir with many thin layers.

c. Take measures to prevent clay swelling.

d. Use packers to achieve steam injection in separate layers to reduce steam crossflow between layers or between wells.

4. Jin 45 Block in Liaohe Huanxiling Field, China

The Jin 45 block had an active edge and bottom aquifer. Its area was 9.05 km^2. CSS was tested from May 1985 to July 1986. Edge aquifer broke in the test well 1824 during the third cycle. Starting in 1986, steam soak was implemented in the entire block using four developing layers. Square patterns of 167 m well distance were used. By June 1991, a total of 295 wells were drilled with 232 well open. The average well oil rate was 9 tons/day and the water cut was 67.2%. Overall, steam soak performed well. The reservoir depth was 8901180 m. The average porosity and permeability were 29% and 800 mD, respectively. There were two groups of layers which had two separate wateroil contacts: 10201060 and 11201160 m. Both layers had edge and bottom aquifers. The reservoir temperature was 44.650C, and the initial reservoir pressure was 10 mPa. The oil viscosity at 50C was 4867696 mPas. During the first cycle, 89% of surveyed 171 wells could flow naturally in the beginning. For the surveyed 111 wells, the percentages of production from natural flow in the entire cycle were 23.3 in the first cycle, 13.3 in the second cycle, and 3.6 in the third cycle. This was because of strong edge and bottom aquifer to provide pressure support. The performance in the first two or three cycles was good. After that, aquifer broke in and the water cut was above 50%. And the oil rate decreased significantly. However, for the wells near edge and bottom aquifer, oil rate decreased more slowly, especially in the first and second cycles. For the wells in the top center area, oil rate and pressure decreased faster; and when water broke in, pressure built up, water cut rose, and steam soak performance became poorer. On the average, the maximum cycles of a single well were 67, and the CSS lasted about 5 years. Several lessons from the CSS in this block are as follows (Liu, 1997):

a. Although edge and bottom aquifer provided pressure support and increased oil rate in the first two cycles, the water breakthrough reduced the number of cycles and deteriorated the steam soak performance. To control the aquifer breakthrough, larger pumps were used in edge wells. For some water coning wells, water shutoff workover was performed.

b. Steam was injected separately into layers so that the steam injection rates in different layers were controlled.

c. It was observed that steam injected broke through neighbor wells. This was because injection pressure was too high, some fractures were formed; and steam broke through along faults. Therefore, steam injection rate, injection pressure, and injection strength should be controlled.

d. Sand production was a problem. Measures must be taken to control sand production.

5. Gudao Field, China

We focus on production techniques in developing heavy oil reservoirs using this field case, the Gudao field in China. The Ng_5Ng_6 sand groups in this field were unconsolidated. The clay content was 7.512%. The porosity was 3035%, the permeability was 7702000 mD, and the initial oil saturation was 5665%. The oil viscosity was 500024,562 mPas. The oil viscosity was sensitive to temperature. If the temperature was raised each 10C above 50C, the oil viscosity was reduced by half. The reservoir depth was about 1300 m. A single well CSS was started in the well Zhong 25420 from August 4 to 27, 1991. The injection pressure was 10.513.5 mPa, and the injection temperature was 270310C with the steam quality of 4075%. The injection rate was 168 tons/day and total of 2206 tons of steam were injected. The initial oil rate was 23.5 tons/day and the production lasted 191 days. A subsequent test well had similar performance. The CSS was extended to larger scales and finally to a commercial scale. Some of production techniques practiced in this field are discussed below.

Well Completion

Low-solid drilling fluid was used (,5% solid). The hydraulic pressure of drilling fluid was not 58% greater than the reservoir pressure. The cement had 3040% silica flour and the cement filled up to the surface. The casing was prestressed with 1.2310^6 N (including the casing gravity).

Sand Control

Owing to unconsolidated sand, several sand control techniques were developed and implemented. In Zhong Er Bei Unit 5, coating sand was used in 78 wells. The treatment was successful in 59 wells and was effective for 171 days (75.6% success rate). However, when applied to 33 wells (times) in another unit, only 19 wells (times) was successful (57.6% success rate).

Another technique for sand control was wiring wrapped screen. The wiring wrapped screens were applied at 292 wells (times); 271 treatments were successful (93.9% success rate) and were effective for 250 days. However, such treatment was expensive. The implementation took a long time resulting in more heat loss. Other tools were being developed to improve the technology.Tests were conducted to combine coating sand and wiring wrapped screens. Wells were filled with coating sand first under high pressure to form a strong stable borehole. Then metal wiring wrapped screens were installed with gravel packing; 26 wells (times) were tested and 24 cases were successful and effective for 198 days.Prevent Clay Swelling Owing to high content of clays (7.5%), clay stabilizing agents were developed. One product was FGW-1, which was a combined system of organic cationic polymer and inorganic compounds. A survey of 35 wells (times) showed 21.8 days longer for cyclic production.

Application of Detergents

The original reservoir pressure was about 12 mPa. The injection pressure in some wells reached 15 mPa. Detergents like BN-5 were used to clean up plugging near wellbores. Nitric acid was also used for wellbore cleanup. Application of Thin Film Spreading Agents Thin film spreading agents like HCS were used to break oil films, to demulsify W/O emulsion to O/W emulsion, and to generate emulsions for improved sweep efficiency.

6. Blocks 97 and 98 in Karamay Field, China

This case is about an ultrahigh viscous oil case. The top of the reservoir was at 70150 m. The average thicknesses of oil zones were 10.5 m in the block 97 and 12.2 m in the 98 block. The formation was the Qi-Gu group. The average porosity and permeability in the oil-bearing layers were 30.6% and 1287 mD, respectively. The vertical permeability was 597 mD on the average. The formation of total dissolved solids was about 3127 ppm. The initial oil saturation was 70.68%. The initial reservoir pressure and temperature at the middle depth of 145 m (155 m subsea) were 1.63 mPa and 17.1C, respectively. The average oil viscosity at 20C was 350,000 mPas. The oil viscosity in the block 98 reduced by 50 times from 20C to 50C. At 80C, the viscosity could reduce to 1000 mPas. The oil viscosity in the block 97 reduced by 100 times from 20C to 50C. At 90C, the viscosity could reduce to 1000 mPas so that the oil could flow in the wellbore and underground.

Field trials and development may be divided into two phases. In the first phase from September 1989 to December 2004, several methods were tested and implemented in these blocks before CSS, such as horizontal wells in the 98 block, and large-diameter wellbores and downhole heating in the 97 and 98 blocks. During the period, reducing oil viscosity using chemicals, microbes, and mixing with light oils was tested. Some of tests in the first phase are detailed below.

a. The first CSS was started in September 1986; 1003140 m^2 well patterns were used. The oil viscosity in the pilot area was 81,016 mPas at 20C. Total of 18 wells were drilled. At the end of the pilot in December 1993, the water cut was 71% and the OSR was 0.24. The total cycles were 3.9, and cumulative oil production per well was 2195 tons on the average.

b. Another pilot area was started in 1988 and started production in 1989 ; 1003140 m^2 well patterns were also used. The oil viscosity in the pilot area was 213,954 mPas at 20C. Total of 48 wells were drilled. By August 2004, the water cut was 69% and the OSR was 0.19. The cumulative oil production per well was 2613 tons and well oil rate was 2.7 tons/ day on the average. In the first two cycles, the production time was about 110 days and the oil production was above 500 tons. The well oil rate was above 4 tons/day and the OSR was 0.22, demonstrating good performance. However, during later cycles, performance became worse. The main reasons were low steam quality due to long steam lines, lowered steam injection strength in the third cycle, and sand production.

c. Total of 141 wells including five large-diameter wells were drilled in another area in the 98 block with relatively lower oil viscosity (172,567 mPas at 20C) in 19931996. By August 2004, the well oil rate was 2.5 tons/day, water cut 70.5%, and OSR 0.25 on the average. For the five large-diameter wells, 4008 tons of oil was produced by 1 well and the OSR was 0.280.39 in the first four cycles. However, starting in the fifth cycle, oil rate and liquid significantly decreased because of low steam injection and low steam quality.

d. Because of the success in using large-diameter wells in the 98 block, a 703100 m^2 inverted 9-spot pattern was drilled (total 9 wells) in the 97 block to further test large-diameter wells. The oil viscosity was 566,869 mPas at 20C. The pattern started production in September 1998. By August 2004, the cumulative oil production was 58,000 tons, cumulative water production 89,400 tons, and cumulative OSR 0.31. The well production time was 1872 days with oil rate 3.44 tons/day and water cut 60.7%. During the test, high steam quality was maintained, and measures like using chemicals to reduce oil viscosity were taken. In 2001 , additional eight patterns were drilled. Because some of wells were not perforated in the main producing layers, low steam quality, and higher oil viscosity, the performance in these patterns was poor. Also considering high cost of drilling, therefore, the method using large-diameter wells was not further expanded.

e. A pilot of 15 vertical injectors and 4 horizontal producers in the 98 block was executed in 1997. The distance between vertical wells or between a vertical well and a horizontal well was about 50 m. The middle reservoir depth was 180 m. The reservoir thickness was 12.5 m and the porosity was 30%. The oil viscosity at 20C was 121,800 mPas. By October 1999, one cycle of steam soak and one cycle of intermittent steam injection had been executed in the four horizontal wells. The oil rates were 8.914.4 tons/day with an initial rate 45 tons/day. Compared with the nearby old vertical wells, the liquid production was 2.7 times, oil production 1.5 times, and oil rate 2.8 times those of vertical wells. However, because these horizontal wells were infill wells (the nearby old vertical wells had been through more than four cycles before drilling horizontal wells), these horizontal wells had high water cut (70%) and low OSR (0.21). In the second cycle, steam broke through and the wells were buried by sand. Owing to high cost of workover, the test was abandoned.

f. Downhole heating was tested in 5 wells in the 97 block in 2004. The oil viscosity at 20C was 1,500,000 mPas or so. By October 2005, the production time was 364 days, and the oil rate was 3.6 tons/day on the average. In the first cycle, the wellhead temperature was 40C, the production time was short (46 days), and the oil production in the cycle was 214 tons per well. In the second cycle, the wellhead temperature was above 70C, the production time was 118211 days, and the well oil production in the cycle was 751 tons. Two more wells were tested and were successful. These tests showed that oil with more than 1,000,000 mPas could be produced using downhole heating.

In the second phase (from January 2005 onward), it was designed to use 70 m square patterns to develop the blocks. According to the development plan, the pipeline to transport steam was shortened from 1.52 to 0.5 km, reducing the heat loss rate from 14.7 to less than 5%. As a result, the steam quality at the wellheads was raised from 60% to above 70%. More horizontal wells were drilled. Screening completion was used to prevent sand production. A large-scale steam injection was implemented in these blocks. At the end of 2005, the oil-bearing area was 5.44 km^2, and the producing oil in place was 19.73 million tons. Total number of wells including abandoned 59 wells was 814. The water cut was 74%, OSR 0.22, recovery factor 8.8%, and well oil rate 2 tons/day.

The performance from these blocks may be summarized as follows.

1. Because of high oil viscosity (50,0001,000,000 mPas at 20C), oil could not flow without heat injection.
2. Steam soak made oil flow naturally. But the production time was 132 days with an average of 7.5 days. Initial rate was high (.6tons/day) but declined quickly (very low rate in 10 days).
3. The oil production and OSR in the second and third cycles were higher than those in the first cycle.
4. Steam breakthrough and sand production were the problems.
5.

7. Gaosheng Field, China

This field in Liaohe, China, had gas cap. Although it also had a bottom water, there was a barrier so that water coning was not observed. The gasoil level was 1510 m, the oilwater level was 1690 m, and the reservoir depth was 15001800 m. The developed area was 14.5 km^2. In the horizontal direction, there were seven blocks among which the blocks 3, 246, and 3618 were the mainly oil-bearing blocks. In the vertical direction, there were eight layers. Among these layers, Layers L1L4 were gas-bearing layers, L5, L6, and L7 were the main oil layers (88% oil in place), and L8 was the aquifer layer. The reservoir thickness was 67.7 m on average. The porosity was 2226% and the air permeability was 10002300 mD. The reservoir temperature at 1600 m was 60C and the initial reservoir pressure was 16.1 mPa. The oil viscosity in situ was 74605 mPas. The oil viscosity decreased to 6 mPas when the temperature was raised to 200220C (Liu, 1987).

Initially the field was produced by mixing light oil and heating rod pumps. Starting in September 1982, CSS was tested and found successful. In 1984, a development plan was designed which included:

1. Five-spot patterns of 210 m later infilled to 150 m.
2. Separately developing L5, L6, and L7 because of existence of gas cap and bottom water.
3. Four phases: initial depletion by mixing light oil and heating rod pumps, CSS, steam flooding, and cold waterflooding.
4. Completion included gravel packing, wiring wrapped screen, and perforated prestressed casing.
5. Wells were drilled along the gasoil ring in L5 to make use of gas cap energy and control pressure.

Because the reservoir was deep, it was important to reduce heat loss through wellbores. Measures to reduce heat loss included tubing insulation, high-temperature metal packer, and filling nitrogen in the annulus. The heat loss was controlled to be less than 12 %.

It was observed that the back-produced water was only 7.8% of the injected. Such low flow back was caused by high content of clay (710 %), especially montmorillonite (90%). Clay swelling adsorbed a lot of water and reduced permeability. The cumulated water slowed down the heat dissipation into the reservoir during injection. To solve this problem, surfactants and chemicals to prevent clay swelling were added in the steam. Adding nitrogen in the steam also helped water production. Adding thin film spreading agents also helped.

To stop gas cap breakthrough, several wells were drilled to produce gas under a controlled mode. The pressure of gas cap was controlled not lower than 8 mPa, and the pressure difference between gas cap and oil layer was controlled.

VII. Simulation software of cyclic steam stimulation:

VII.I. PETREL simulation software

From the petroleum engineering programs, which Schlumberger introduced to the world of the oil industry, it entered all fields of exploration, exploitation, reservoir and drilling. In the new version of this software, additional facilities have been provided to facilitate the work. Also, to speed up work and quick access to data, online work feature is provided in which the user can enter his data into the central server, and other related users check it based on access restriction rating and changes Apply requirements, then save the update. A program used to model oil and gas reservoirs, and is usually done in building geological models (petro physical properties) and distributing them over the reservoir. In addition, a dynamic model is built that consists of production data (pressures, production, injection), which can be linked to the reservoir simulation, the simulation and the history match.

VII.II. CMG simulation software

Programs used to simulate oil and gas reservoirs, in which development plans can be drawn up for the field and selection of the best well locations, in addition to the ability to design improved extraction processes and evaluate their performance. ECLIPSE Reservoir Simulator is a comprehensive and complete program for simulating types of reservoirs of any degree of structural, geological or fluid complexity. ECLIPSE Applications Due to its wide capabilities and abundance compared to other similar simulation software, it can be said that it has become a global standard. This software is available in different versions, some of which are described below. is being ECLIPSE 100 , ECLIPSE 300, In addition to having the features and capabilities of ECLIPSE 100, the ECLIPSE 300 software can use equations of state or pressure-dependent equilibrium ratios to solve problems.

ECLIPSE FEATURES :

*Simulation of hydrocarbon tanks in the form of composite black oil

*Ability to simulate overheating (thermal simulation)

*Ability to simulate oil tanks in parallel to reduce simulation time

*Excellent interaction with PETREL modeling software

*Ability to simulate chemical harvesting methods such cyclic steam stimulation.

*Excellent interaction with reservoir fluid properties simulation software.

* Excellent ability to simulate large industrial projects

*Excellent ability to simulate unusual oil and gas reservoirs.

VIII. INTRODUCTION TO STARS TUTORIAL

Opening BUILDER

1. Open **Builder** by double clicking on the appropriate icon in the Launcher.
2. Choose:
   - **IMEX** Simulator, **FIELD** Units, **Single Porosity**
   - Starting date **2005-01-01**
3. Click **OK** twice.

Create an IMEX Black Oil, Heavy oil Dataset Using 'Quick Pattern'

4. Click **Reservoir** (on the menu bar or in tree view) and **Create Grid**.
5. Select **Quick Pattern Grid** and enter the following:

Note: units will be applied automatically

Pattern Type: **Normal 5-spot** Top of Reservoir: **1600** (ft)

Pattern Area: **10** (acres) Approx. Block Thickness: **6** (ft

Thickness of Reservoir: **100** (ft) Approx. Block Size in X,Y: **20** (ft)

6. Click **Calculate**. The results from your input will be displayed.
7. Click **OK**.
8. Click on the **"Specify Property"** button (top middle of screen) to open the **General Property Specification** spreadsheet as shown below.

In the box for ***whole grid***, input **0.3** for **Porosity**, **2000** (mD) for **Permeability I** and **J,** and **1000** (mD) for **Permeability K**.

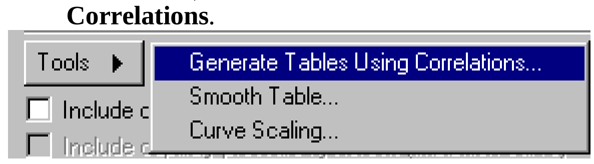
9. Press **OK** to leave the General Property Specification section and **OK** again to **Calculate Property**.
10. Under **Reservoir** in tree view menu, double click on **Rock Compressibility** and input **1.8E-6** 1/psi in the ***rock compressibility box***, **1250 psi** in the ***reference pressure box***, and press **OK**. Units will be applied automatically. You should now have a **green** check mark for the **Reservoir** section.

Generate Black Oil PVT Properties from correlations

1. There are several options available for creating a fluid model. If a PVT analysis exists, the data may be entered directly or copied and pasted from a spreadsheet file. Alternatively, CMG's WINPROP software may be used to generate PVT data in a compatible format. Here, we will assume that limited data is available.
2. Given that a gas cap exists, it will be assumed the reservoir fluid is at saturated conditions and the initial measured datum pressure of 1250 psia represents the bubble point. The API gravity is 21°, gas specific gravity is 0.65 and the live oil viscosity is 120 cp. Initial production testing showed a producing GOR of 172 SCF/bbl.
3. In Builder, click on **"Components"** in the tree view, click on the  button and select **"Quick Fluid Model"**. Then select: Launch Dialog to create a quick BLACKOIL model using correlations, then **OK**.
4. Enter the reservoir temperature of **100 °F** and a maximum table pressure value of **1800** psi (maximum expected pressure in the model). Initially, we will assume the bubble point pressure is valid and will enter **1250 psi** in row 3 from the drop down menu under **Value provided**. Select **Stock tank oil gravity (API)** from the drop down menu for row 4 and enter a value of **21**. Similarly for row 5, select **Gas gravity (Air=1)** and enter a value of **0.65**. Leave the rest as default and select OK to accept these values (and closing the panel). The plot of the PVT properties then comes up.
5. Move the cursor on the plot to check the values of Rsi and Boi. Note the value of Rsi is acceptably close to the field measured value. Click to view the Eg and Viscosity plots. Note the oil viscosity is in the order of 10 cp, much lower than the data value of 120 cp.
6. Click on **PVT Region: 1** in the tree view and select the **PVT Table** tab. Click on the oil viscosity column (viso). Then select **Tools** and **Shift Column values to Match** and enter the Pressure and Column values as 1250 and 120, respectively. Note that in the PVT Table, there is a new row at a pressure of 1250. Note the values at the bubble point pressure are as expected. Select **OK**. This would be a good point to save the dataset you are working on. Click **File** then **Save as** Tut_Imex.dat

Creating Relative Permeability Data

1. Click the **Rock-Fluid** tab in the tree view.
2. Double click on **Rock Fluid Types** in the tree view. A window will open. Click on the  button and select **New Rock Type**.
3. Press the **Tools** button (on the **Relative Permeability Tables** tab) and select **Generate Tables Using Correlations**.



Enter the following parameters for the analytical relative permeability curves generation:

SWCON **0.3**

SWCRIT **0.3**

SOIRW 0.4

SORW 0.4

SOIRG 0.0

SORG 0.0

SGCON0.05

SGCRIT **0.05**

KROCW **1**

KRWIRO **0.3**

KRGCL **0.3**

KROGCG **1**

All Exponents **2.0**

4. Press **Apply** and then **OK**. Press **OK** again to get out of the **Rock Types** window. A graph containing the relative permeability curves will appear. The **Rock Fluid** section should have a **green** check mark.

Creating Initial Conditions

1. Click the **Initial** tab on the tree view of **Builder**.
2. Double click on **Initial Conditions**.
3. Select **Water, Oil, Gas** as the initial fluid in the reservoir to perform a Gravity-Capillary Equilibrium Calculation.
4. Type the following values in the available fields:

1250 (psi implied) for **Reference Pressure**

1600 (ft implied) for **Reference Depth**

1720 (ft implied) for **Water-Oil Contact**

1590 (ft implied) for **Gas-Oil Contact**

Under **Bubble Point Input Format**, set the bubble point to constant value of **1250** (psi implied)

5. Leave the other boxes blank.
6. Click on **Apply**; then **OK**. You should now be back in the main Builder window with all tabs showing a **green** checkmark in the tree view, except for the "Wells & Recurrent" tab.

Complete the Well Perforations

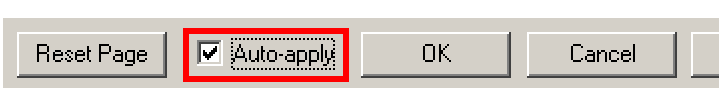
1. In the tree view press the **Wells & Recurrent** tab.
2. Expand **Wells,** expand **Injector 1**, and double click on **2005-01-01 PERF**.
3. Go to the **Perforations** tab.
4. We want to perforate the injectors in layers 4-15. Under **User Block Address**, by clicking with your mouse and holding down the Ctrl key to select multiple items, highlight layers **"1 1 1 – 1 1 3"**.
5. Click on the  button to delete these layers. You should now have a range of perforations from layers **1 1 4 – 1 1 15**.
6. Click **Apply**.
7. Repeat steps 3 - 6 for all other injectors (i.e. Injector 2 – 4) by selecting each well from the drop down box under **Well& Date:**.

We want to perforate the producer in layers 4 – 10. Repeat steps 1 - 6 for **Producer 1** except now the range should be from **18 18 4 – 18 18 10**.

8. Click **OK** and save your file.

Adding Operating Constraints

1. In the **Wells & Recurrent** tab, expand **Wells** and double click on **Injector 1**.
2. Check the **Auto-apply** box at the bottom of the window. This will insure that all changes are applied automatically.



3. Go to the **Constraints** tab.
4. Under **select new** (in the Constraint column of the table), select **OPERATE**. Then select **BHP bottom hole pressure, MAX, 1800 psi, CONT REPEAT**.
5. Repeat step 4 to add another operate constraint, except this time select **STW, MAX, 630** bbl/d**, CONT REPEAT**.
6. Go to the **Injected Fluid** tab and choose **Water** as injection fluid.
7. Now, we can copy all the above specifications to the other injectors. To do that, make sure you are looking at "Injector 1" in the **Name/Date** list. Then highlight the following Events (for Injector 1) using your mouse and the Ctrl key: **INJECTOR**, **constraints**, and **injected fluid**. Press the **Tools** button at the bottom of the screen, and select **Copy events using filter**. This will open a new window.
8. In the **1.-Select Wells** tab, under **Auto Select Wells**, click on **Injectors** and press the **Select** button.
9. Then go to the **2.-Select Dates** tab. Under **Auto select dates**, check **All** and press the **Select** button. Then press the **Search & Add** button.
10. Click **OK** and the same constraint information created for Injector 1 will now be copied to all injectors. Click **OK** again.
11. Now double click on **Producer 1** and set the operate constraints the same way as in steps 2 – 5.

- **BHP, MIN, 30** psi**, CONT REPEAT**
- **STL, MAX, 2520** bbl/d**, CONT REPEAT**

12. Click **OK**.

Adding Dates

1. In the **Wells & Recurrent** tab, double click on **Dates**.
2. Click on  to **Add a range of dates**. Choose **From: 2005-01-01, To: 2010-01-01,** by **Month**. Click **OK** and click **OK** again to the message that appears.
3. In the ***set STOP*** column, check on **2010-01-01** so the simulator knows to stop at this date. Click on **Close**.

Outputting Basic Properties and Well Information

1. Click on **I/O Control** in the tree view.
2. Double click on **Simulation Results Output**.
3. Under the *OUTSRF* section, change the "Well" ***Information*** to **All well values (ALL)**.
4. For "Grid" ***Information*** press the **Select** button and a new window should pop up.
5. Check the boxes for the following (if not already checked):

Oil saturation (SO) **Pressure (PRES)**

Gas saturation (SG) **Triggers the output of…… (STRMLN)**

Water saturation (SW)

6. Deselect all other variables.
7. Press **OK** twice to get back to the main Builder.
8. All tabs in the tree view of Builder should now have **green** checkmarks. Save the file.

Validate Dataset Using Builder

1. Right click the white space in the tree view and select **Validate**. A window will pop up letting you know the status of your input information.
2. Another method can be used to validate your data file. Click the **Validate With IMEX** button near the top of Builder.
3. A message will prompt you to save. Do so if you have not already saved and a new window will appear.
4. Check **Validate** and press the **Run/Submit** button.

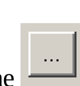
Note:The simulator can also be fully run at this point by choosing *Run normal* instead of *Validate*; however the results can only be viewed in this window.

5. A brief output will be displayed, listing any warnings or errors with the dataset. Press **Close**.
6. Fix any warnings or errors; otherwise save your dataset and exit Builder.

Running the Simulator

1. Go to Launcher and drag & drop **Tut_Imex.dat** into the **IMEX 2006.10** icon. A new window will pop up. Press the **Run Immediately** button.
2. If there are no errors, a MS-DOS window will open up and show the progress of the run. When the run is finished, a brief summary of results will be displayed.
3. Check to make sure initial conditions are as expected by reviewing the **.out** file which was created during the run. The file can be viewed by using an editor (***TextPad, PFE32***, or ***Notepad***).

Converting the Dataset to STARS Using Builder

1. Load **Tutorial.dat** back into builder 2006.10.
2. On the menu bar, click **File, Converter simulator type for dataset**, and **To STARS**.
3. A window will come prompt you to save. Save file if you wish.
4. Click on the  button to save a file in your current directory and input **Tutorial_stars.dat** for the filename.

5. Under ***Fluid model import/conversion***, select **Will enter later** and click **OK**.
6. A warning will appear listing the keywords that have been dropped when converting IMEX to STARS. Note that these include several of the **I/O** keywords. Press **OK**.
7. Some rock and thermal properties will now have to be entered. Click on the **Reservoir** double click on the Thermal Rocktypes in the data tree; you should be under the **Rock Compressibility** tab.
8. If not already entered, input the following:

- Porosity Reference Pressure (PRPOR) **1250** psi
- Formation Compressibility (CPOR) **1.8E-06** 1/psi

9. Go to the **Thermal Properties** tab and input the following:
    - Volumetric Heat Capacity (ROCKCP) **35** Btu/ft3-F
    - Thermal Conductivity of Reservoir Rock (THCONR) **24**
    - Thermal Conductivity of Water (THCONW) **8.6**
    - Thermal Conductivity of Oil (THCONO) **1.85**
    - Thermal Conductivity of Gas (THCONG) **.64**
10. Go to the **Overburden Heat Loss** tab and input the following for both Overburden & Underburden:
    - Volumetric Heat Capacity: **35** Btu/ft3-F
    - Thermal Conductivity: **24** Btu/ft-day-F
11. Click **OK**.

Generate Equivalent STARS Fluid Model, Based On the IMEX Black Oil PVT

1. Click on the **Components** right arrow and select **Import Blackoil PVT**. Select Units Field enter the reservoir temperature of **100 F**. Then click the **Read Black Oil PVT Data in IMEX Format**. Select the IMEX data file Tut_Imex.dat and click **Open**. The panel should look like the following:
2. Note that in the above form, if the button **"*Launch the Black Oil PVT Graphical User Interface (GUI)*"** button is clicked, the black oil PVT data could be generated the same way that it was done for the IMEX data file in the third section of this tutorial entitled "**Generate Black Oil PVT Properties from correlations**".
3. In the Bubble Point Pressure section of the panel, click on **Select From Table** and click on the grey box next to the 1250 psi value in the pressure column. Click on **Next>** which take you to Step 2. Note the various elements that have been selected by default. We will accept these selections/values, but in reality, they may be changed by the user.
4. Assuming we have a measurement of dead oil viscosity of **420** cp and **5** cp at reservoir and maximum steam temperature **100** and **450**, respectively. Enter these values in the table. Note that under the Component System part of the panel, we are creating a live oil system. Also in the Gas K Value Temperature Dependence part of the panel, we are accepting the default value. Click **Next>**. A message will appear regarding the thermal expansion coefficient with a default value that we will accept. Click **OK** which takes you to Step 3 (Check Matches of PVT Properties).
5. Move this panel to the side to enable viewing of the match plots. Note the **Match error** values shown in the Step 3 panel. Check the match quality by expanding and clicking on the various available plots. Matches are acceptable, given the limited PVT data available. Note that the Gas Viscosity plot appears not to match. This is because the STARS uses an effective liquid viscosity for gas in the liquid phase.
6. On the Step 3 panel, select **Next>** and then **Finish** on the Step 4 panel which has come up. Note that in the tree, the Components tab now has a **green** checkmark.
7. Search for the word **"MFRAC"** and note that Builder has created mole fraction values for the two components "Dead_Oil" and "Soln_Gas". **Save** and close the data file.
8. Open the file you saved with the mole fractions vs. pressure (bubble point pressure). You should find that the mole fractions appearing in the data set correspond to those in the table at a pressure of 8576 kPa or 1250 psi(saturation pressure).

Pressure	**Dead_Oil Composition**	**Soln_Gas Composition**
14.696	**0.991355**	**0.0086454**
97.0496	**0.96766**	**0.0323401**
179.403	**0.941541**	**0.058459**
261.757	**0.914677**	**0.0853234**
344.11	**0.887794**	**0.112206**
426.464	**0.861289**	**0.138711**
508.818	**0.835395**	**0.164605**
591.171	**0.810251**	**0.189749**
673.525	**0.785938**	**0.214062**
755.878	**0.762498**	**0.237502**
838.232	**0.739947**	**0.260053**
920.586	**0.718285**	**0.281715**
1002.94	**0.697498**	**0.302502**
1085.29	**0.677564**	**0.322436**
1167.65	**0.658458**	**0.341542**
1250	**0.640149**	**0.359851**
1360	**0.616884**	**0.383116**
1470	**0.594909**	**0.405091**
1580	**0.574145**	**0.425855**
1690	**0.554517**	**0.445483**
1800	**0.535952**	**0.464048**

9. **Save** and close the data file. Load **Tut_STARS.dat** back into builder.
10. Also check initial conditions to make sure they have been transferred correctly

Modifying Relative Permeability Curves for Steam Injection

Note:

With steam injection, it is usual to expect changes in end-point saturations as a function of temperature. This is accomplished using the tabs available in the Rock-Fluid section.

Additionally, it is recognized that the flow properties of injected steam are much different than the flow properties of evolved solution gas. When gas comes out of solution, the smallest pores are occupied by gas first and have the highest gas saturation. When gas or steam is injected, it is the largest pores that are occupied first. Therefore, it is expected that flow properties between the two cases should be different.

This is accomplished in STARS using relative permeability interpolation which is based on the composition of the water component in the gas phase as the interpolation parameter. If the composition of water in the gas phase (steam) is low, then the low relative permeability curves associated with gas evolution are used. If the composition of water in the gas phase is large, the high relative permeability curves associated with gas or steam injection are used.

1. Go to the **Rock-Fluid** tab and either Click on the arrow to the right, then select **Create/Edit Rock Types** or simply Double Click on **Rock Fluid Types** in the tree view.
2. From the Rock Types panel that comes up, Click on the **Relative Permeability End Points** tab.
3. Ensure there are at least 2 Temperature Intervals specified and enter the minimum and maximum values

for the temperature range as **100** and **450**, respectively. These temperatures will then show in the lower table. Comments may be added at this point.

4. To overwrite individual critical saturation and endpoints from the original tables, Click on the blue triangle for whichever parameter is to be changed and from the drop down menu, select Temperature dependence. Here, we will change SWR, SORW and KRWRO. The values at 100 F will be the ones in the original tables. The values at 450 are to account for changes due to steam injection. Columns will appear in the KRTEMTAB table and should be filled in as follows:

Parameter	SWR	SORW	KRWRO
T=100	0.3	0.4	0.3
T=450	0.4	0.3	0.4

5. Click **OK**. To view the effect on the relative permeability curves as a function of temperature, Click on **Rock-Fluid**, then the right arrow and select **Diagnostic Plots**. **Toggle** the Oil Water and Gas Oil buttons. In the case of multiple rock types, if you click on Reservoir to display any property and have the Rock Fluid Diagnostics panel open, clicking on any block will change the diagnostic plot to show that corresponding to the UBA.
6. Pick the **Ternary** display. Note that only one temperature at a time can be selected. Check that the Kro (intermediate phase relative permeability) does not touch the zero oil saturation line at either temperature. If it does, the Stone 2 formulation has failed and another 3-phase relative permeability option should be chosen.
7. **Close** the **Diagnostics panel** (x in upper right hand corner).
8. Basically, the two curves generated by changing the endpoints represent two different temperature regions in the reservoir. They do not reflect the fact that phase composition may also affect relative permeability.

At original reservoir temperature, the curves apply to a region in which steam is absent (solution gas only in the gas phase); at high temperature, the curves apply to the region heated by steam (which may, or may not, have a high concentration of the water component in the gas phase). Depending on whether or not a region contains principally water or solution gas in the gas phase, we would like to apply a different gas relative permeability curve. This is done using the interpolation option.

9. Click on **Rock-Fluid** and the right arrow to bring up **Create/Edit Rock Types**. Select the **Rocktype Properties** tab and check "Use Interpolation sets". Also, enable interpolation components (INTCOMP) as shown in figure below. Set the component for interpolation as **WATER** and the Phase from which component's composition will be taken as **gas mole fraction**.

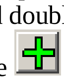
10. Goto the **"Interpolation set parameters**" tab and input a value of 0.2 for DTRAPW and DTRAPN. This means if the water mole fraction in the gas phase is less than 0.2 (no contact with steam), the first table will be used.

11. Go to "**Relative Permeability Tables**" tab. Click on the arrow on the right of the "Interpolation sets" and select **Copy Current Interpolation Set**. This will create a second interpolation set which is a copy of the first which we can modify.
12. Now click on **Tools** and select **Generate Tables Using Correlation**. Leave the parameters as they are EXCEPT for KRGCL which should be 1:

SWCON	**0.3**
SWCRIT	**0.3**
SOIRW	**0.4**
SORW	**0.4**
SOIRG	**0.0**
SORG	**0.0**
SGCON	**0.05**
SGCRIT	**0.05**
KROCW	**1**
KRWIRO	**0.3**
KRGCL	**1.0**
All Exponents	**2.0**

13. Keeping the "Interpolation sets" selected as 2, go to **Relative Permeability End Points** tab and input values of temperature dependence similar to step 4 described above.
14. Also, input the interpolation set parameters for interpolation set 2. Set the DTRAP values to 0.6. This means if the water mole fraction in the gas is greater than 0.6, the second table will be used (with higher gas relative permeability as shown in the next step). For water mole fraction values between 0.2 and 0.6, an interpolation between the two relative permeability curves will be made.
15. Finally, apply cubic endpoint smoothing to all curves by selecting each set and setting the cubic smoothing option.
16. Click **OK**
17. View the diagnostic plots from Rock-Fluid, right arrow for both Oil Water and Gas Oil buttons.
18. Save the data set.

Complete the Dataset

19. Go to the **Numerical** tab in the tree view. Double Click on **Numerical Controls**. Press **OK** to the warning that pops up.
20. In the ***DTWELL*** box, type **1E-3**.
21. In the ***UPSTREAM*** box, select **KLEVEL**.
22. Set **ITERMAX** and **NORTH** to **90**
23. In the ***AIM*** box, select **Stability Switching Criterion**. Click **OK**.
24. Go to the **Wells & Recurrent** tab and set the constraints and injected fluid (fluid, mole fraction, temperature, and quality) for all wells in the same manner as before (if not already set).
    - Injectors - Injection fluid: **Water**, mole fraction of water: **1**, Temp: **544 F** Steam quality: **0.70**
    - Injectors at a **max BHP** of **1000 psi, STW** of **630** bbl/d, and **cont repeat**
    - Producer at a **min BHP** of **30 psi, STL** of **2520** bbl/d**,** and **cont repeat**
25. Click **OK**.
26. The *<u>I/O Control</u>* keywords should have been converted from IMEX to STARS, but we want to add some additional parameters. Click on **I/O Control** in the tree view and double click on **Simulation Results Output**.
27. Click the  sign again and select **2005-01-01** and **Grid.** Click **OK**; press the **Select** button and a new window should pop up.
28. Check the boxes for the following:

Oil saturation (SO)	**Comp. comp. in gas phase (Y)**
Gas saturation (SG)	**Comp. comp. in oil phase (X)**
Water saturation (SW)	**Viscosity (VISO)**
Temperature (TEMP)	**Oil density (MASDENO)**
Pressure (PRES)	**Water, oil, gas relative perms (KRW,KRO,KRG)**

Review the variable description list and select any other output which may be of interest. Note that this will increase the size of the output files.

29. Deselect all other variables. It should look like Figure 10 when you are done.

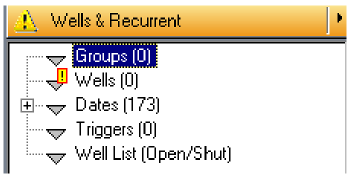
30. Press **OK** twice to get back to the main Builder.
31. You should now have all **green** checkmarks in the tree view. Save and close your dataset.

32. Run the dataset by drag & dropping **Tutorial_stars.dat** into the **STARS** icon and pressing the **Run Immediately** button.
33. Compare initialization of the run for consistency with IMEX.
34. Compare performance between the two simulators.

Building a Cyclic Steam Simulation Model in STARS

1. Load the **CSS_START.dat** file into Builder.
2. You should see an screen like this:

3. We have no wells yet, nor constraints .However, there is a set of dates giving suitable output times. The next step shows where the 5 wells should be placed.



4. The wells should be located as showed below:

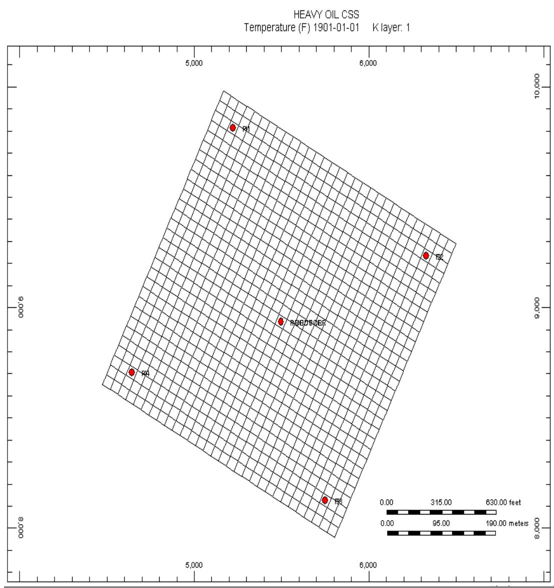


FIGURE 21. CSS-2011

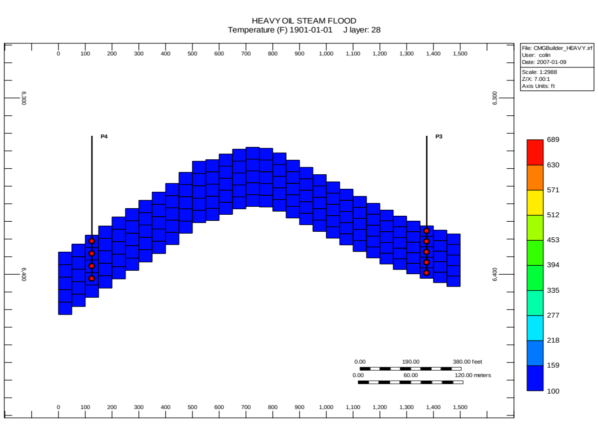


FIGURE 22. CSS-2011

5. For CSS we actually need to add 10 wells since each location in the 5-spot requires both an injector and a producer. The easiest way to do this is to add 5 of the wells and copy them to make duplicates. The coordinates and names for the wells are:
   - **I1, P1 3, 3**
   - **I2, P2 28, 3**
   - **I3, P3 28, 28**
   - **I4, P4 3, 28**
   - **INJECTOR, PRODUCER 16, 16**
6. Double click on wells, enter the name "I1", and define it as an "INJECTOR MOBWEIGHT IMPLICIT"
7. Add the remaining 4 injectors
8. To set the locations, expand the well list and double click on the Perforations for the first well:
9. Click "Begin", move the cursor over to block 3, 3 on the grid, and left click. You may need to click twice.
10. Then click "Stop" and "Apply".
11. Select the next well from the drop down box at the top of the Perforations window and repeat the process for the next well location.
12. When all 5 wells are added we want to add additional layers to the completions as they have only been added to the top layer. Add perforations as shown in the following figures:

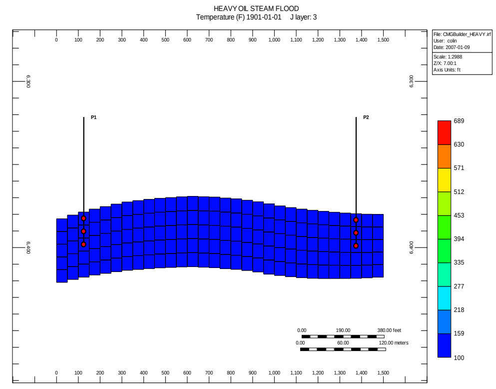


FIGURE 23. CSS-2011

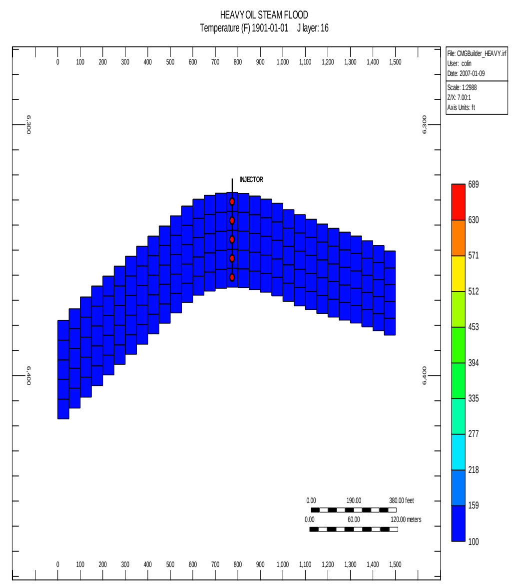


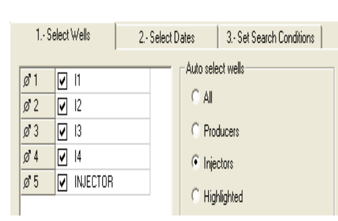
FIGURE 24. CSS-2011

13. For I1 and I2 we see that the completions are in layers 1-3
14. For I3 and I4 we see they are in layers 1-5 for I3 and layers 1-4 for I4
15. INJECTOR is completed in all 5 layers
16. Select I1, click inside the cell with the completion, and replace the 1 with 1:3. Click "Apply"

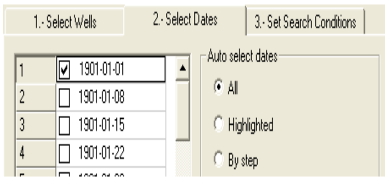
17. Repeat the process for the other 4 wells and click OK to close the completions window.
18. Double click on well I1 in the well list and select the Constraints tab. Check "Constraint definition"
19. Add the following operating constrains in the same order showed:

20. The operating constraint for the injectors is a bottom-hole pressure of 2500 psi.
21. We now add the steam conditions consistent with 2500 psi and the injection composition.

22. Highlight all the components of well I1, click on Tools (or right click on top of the highlighted region), and "Copy events using filter"
23. Select the wells:



24. Select Dates:



25. Click "Search and add" and OK

#	Well	Date
1	I1	1901-01-01
2	I2	1901-01-01
3	I3	1901-01-01
4	I4	1901-01-01
5	INJECTOR	1901-01-01

26. Click OK to finish and close this screen
27. Save the data set as **CSS_START_Completed.dat**
28. Now to copy the wells, Click on the little black triangle of Wells & Recurrent and select "Copy well"
29. Select injectors
30. Click Next.
31. Select **Copy all Perforations** and click Next
32. Select **Copy Geometry** and **Use the geometry that is specified for the copied perforation** and click next twice.
33. Select **I will manually enter the new well name in the next step** and **Use the original well's definition date**
34. Click next and name wells P1, P2, P3, P4 and Producer
35. Select P1, Constraints tab, and add the constraints shown below:
36. Repeat this (or copy) the constraints to all producers at the date of 1901 01 01
37. Click OK and save the data set.
38. We now have a complete data set BUT - all the wells are open at the same time.
39. We can use this data set to create a number of data sets which can investigate both CSS and alternative processes such as primary, water flood, and steam flood
40. There is also some customizing we need to do depending on the process we are going to investigate. Make sure the data set is saved.

Cyclic Steam Stimulation

1. Load the base data set into Builder and save it with a new name. The data set is pretty much set up – only a few extra steps. Use Time-line view to see how the wells are currently configured. We have 5 producers and 5 collocated injectors
2. We need to ensure that only one well in a pair is open at the start. We need to define cyclic groups (producer/injector pairs). We need to define cycle parameters for forecasting.
3. Note: if you are matching historical cycling data you would import these data into Builder in the normal way and the switching between injection and production will be controlled by the data. This is no different from any other history match and does not require a special approach. What we are doing is what is required in order to forecast cyclic steam performance.
4. Under **Wells & Recurrent**, right click on **Groups** and select **new.**

Add a group named **FIELD** and then click on **Add new group**. Add a group named 'CYC_GROUP 1'. Repeat this process to add groups thru and including 'CYC_GROUP 5'

5. So we now have the five cycle groups defined. We need to assign the individual wells to each group. Double click on 'CYC_GROUP 1' and attach wells I1 and P1. Repeat this process for the other 4 groups.
6. You can then go to the arrow at the right of **Well & Recurrent** and use **Group and Well Connections** to see the well grouping graphically
7. We must now define the constraints for each cycling group. Double click on CYC-GROUP 1 to open the Group Events window which is very much like the Well Events window we have used earlier. Full in the group information as in the figure below. This cycle group will first inject steam at a maximum rate of 250 STB/D CWE for 30 days followed by a 5 day soak period and then produce at a maximum liquid rate of 250 STL/D for 180 days. If the oil rate falls to 5 STB/D, production will end and the next injection cycle will begin.
8. The other cycle groups will have the same constraints. Copy the constraints from group 1 in the same way we copied well events.
9. Save and run the data set.
10. Open Results Graph and create a single well graph of oil rate for one of the producers. Cycles can be clearly seen. Add the cumulative oil curve.

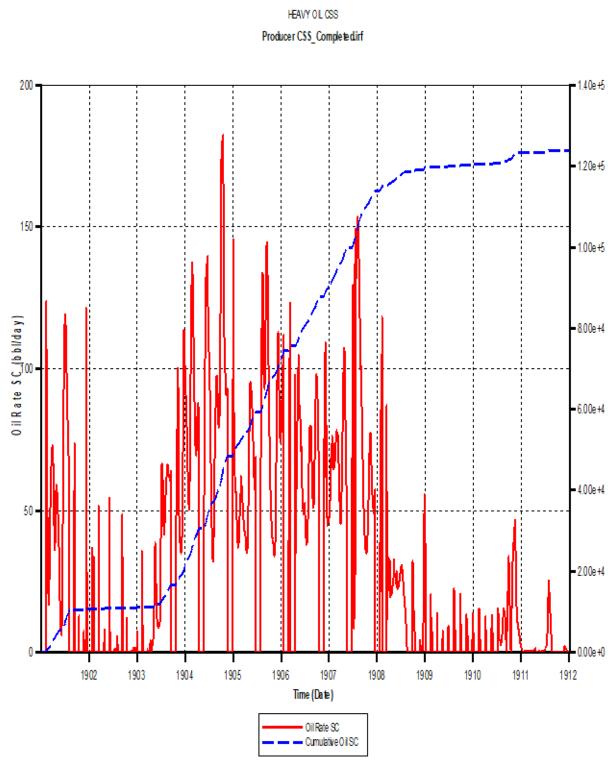


FIGURE 25. CSS-2011

11. Create the plot below for the central injection well, INJECTOR.

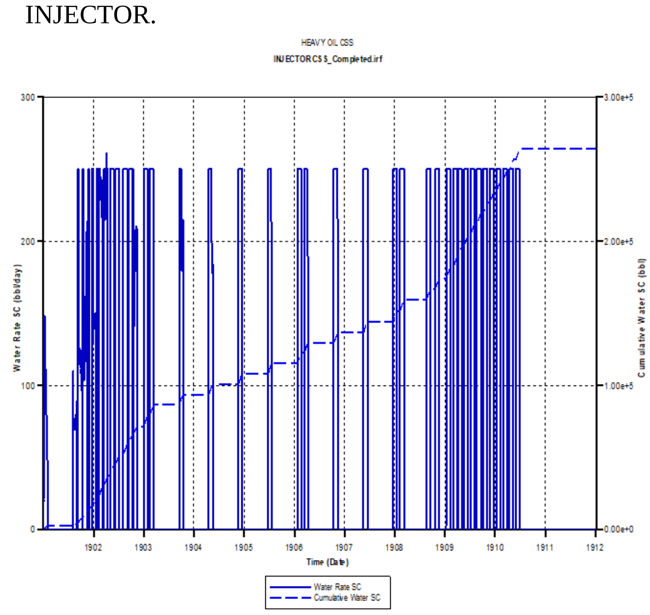


FIGURE 26. CSS-2011

12. Select New Plot. and answer "No" to the query. Plot field cumulative oil produced and also field cumulative water (steam) injected. Probe and note the values for production and injection.

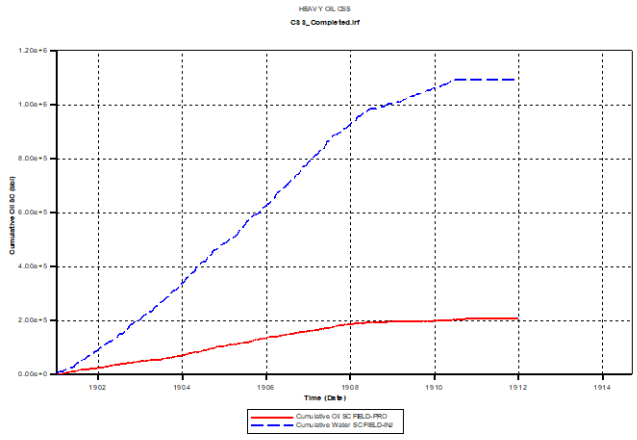


FIGURE 27. CSS-2011

IX. SIMULATION ON CMG

A simple example was used for a reservoir with five injection wells and five production wells. The values of permeability, porosity and thickness (2000 m, 0.3 and 6 ft) were using CMG-STRRS software.

It was calculated as in Figure (21) and we made many changes in permeability, porosity and thickness, we apply them in oil production and note the size of the change in oil production and note the effect of the change in

Oil production permeability after making changes, and we can see this more clearly in Figure (21) through the application. We can summarize. Cycle steam can be used in reservoirs where the permeability and porosity are large and the thickness is low.

As shown in the table (6).

Table 6. Cyclic steam stimulation

Case	Thickness	porosity	Permeability	Oil Recovery – EOR-CSC SCTR
1	6 ft	0.3	2000 md	15
2	6 ft	0.15	2000 md	20
3	6 ft	0.3	1000 md	12
4	3 ft	0.3	2000 md	17
5	6 ft	0.15	1000 md	15
6	3 ft	0.3	2000 md	26

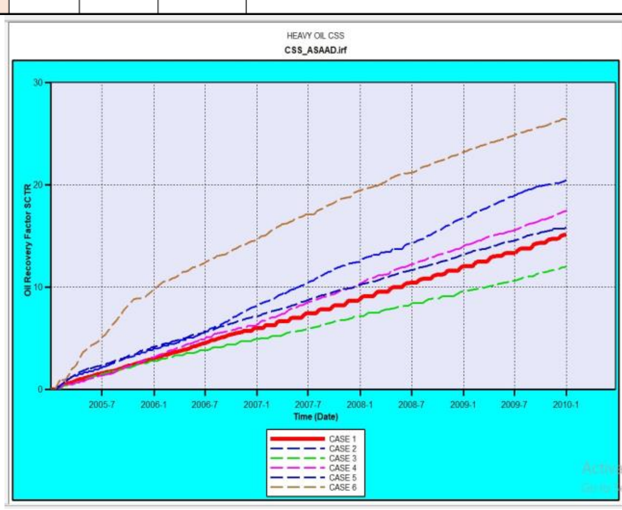


FIGURE 28. **Oil Recovery – EOR-CSC SCTR**

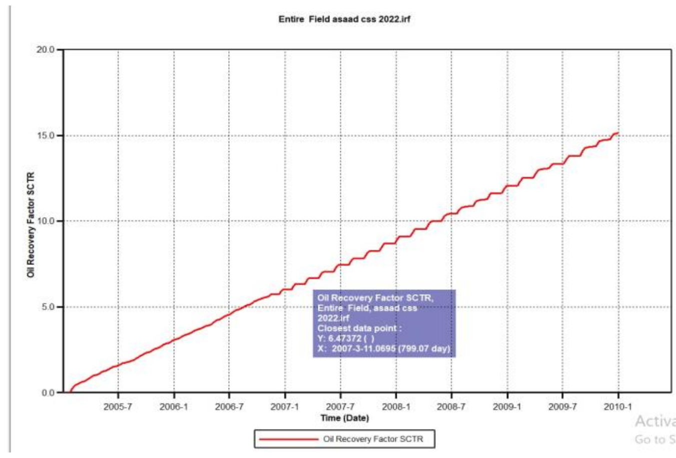


FIGURE 29. **Oil Recovery – EOR-CSC SCTR**

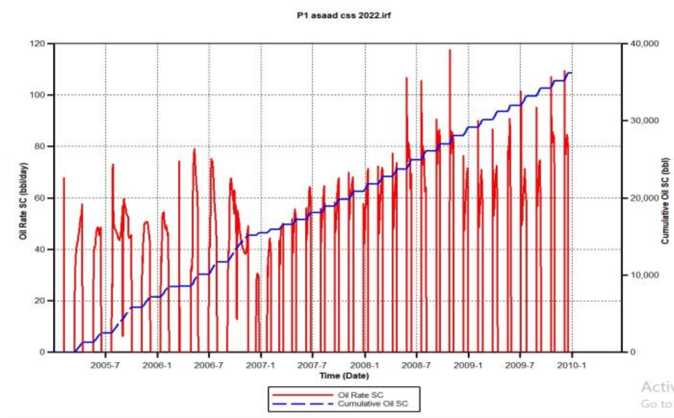


FIGURE 30. **Oil Recovery – EOR-CSC SCTR**

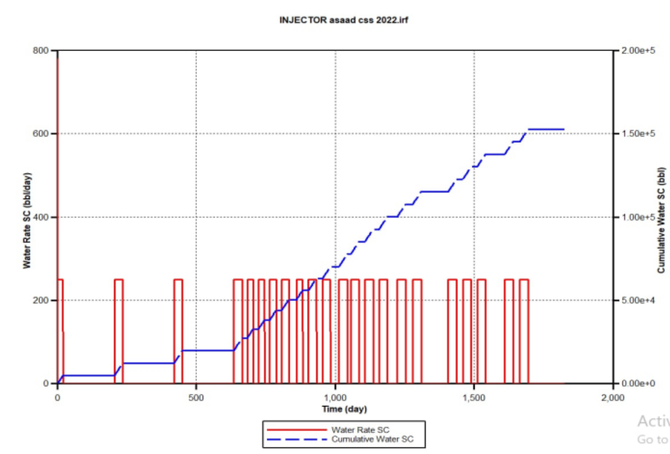


FIGURE 31. **Oil Recovery – EOR-CSC SCTR**

X. Conclusion:

1. *This research can be used as a manual or a guideline for engineers and workers in the oil fields through which they know when cyclic steam succeeds and when it fails.*
2. *This research collected analyzed data from different technical aspects to investigate the best reservoir characteristics which make the cyclic steam -EOR more successful.*
3. *This research states that EOR have been found to be commercially successful.*
4. *This research provided important guidelines on where and when the huff-n-puff can be used over the flooding mode and vice versa.*
5. *This study pointed out some conditions where the cyclic steam stimulation-EOR could fail.*

XI. Limitations:

The major limitation of cyclic steam injection is that it leaves considerable amounts of oil in the reservoir that can only be recovered by drive processes and it is observed that less than 30% (usually less than 20%) of the initial oil in place can be recovered. One more limitation of this process is that it is preferred production on heavy oil reservoirs that can contain high pressure steam without fracturing the overburden.

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