Recovery in Thin Multi-Layered, Medium Heavy Oil Reservoir: A Simulation Study

by

Chua Ai Tieng

Dissertation submitted in partial fulfilment of
the requirement for the
MSc. Petroleum Engineering

JULY 2012

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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Universiti Teknologi PETRONAS

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Approved by,

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Prof. Dr. Mariyamni binti Awang

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

July 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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CHUA AI TIENG

ABSTRACT

Recovery of heavy oil from thin multi-layered reservoir is a challenging task in places such as China, Thailand and Oman. Thin layers with average thickness of 2.5 m (8.2 ft) and lower contribute to an inefficient steamflooding was reported by Liu *et al.* [**1**] as one of the factors resulting in non-commercialization for steamflooding in B92, Taobao field.

This project aims to develop a 3D-model with compositional oil components that can handle thermal option. From there, the model is developed further to investigate five reservoir properties and improve recovery of a Base Case.

"Schlumberger ECLIPSE 300" was used to investigate all cases and scenarios in this project. Base Case constructed has one injector completed only at permeable layers and one producer. It has a 20 × 20 × 20 Cartesian grid size representing 600 ft × 600 ft × 100 ft reservoir.

An example of such a field in this region is Bokor field, Malaysia. It has a range of viscosity between 10 cP to 230 cP, porosity range of 15% to 30%, and permeability values between 50 mD to 4000 mD. These parameters with frequency and thickness of sand and shale layers were investigated. In comparison of recovery factor, porosity variation proved to be the most sensitive parameter in both water flooding and steam flooding.

In the second part of this project, recovery of Base Case generated was improved by 7% through decreasing injection rate by 67% and steam viscosity to 0.5 cP. This yielded a reduction of steam-oil mobility ratio by 98%. In this case, water cut at the end of five years was reduced by 4%, and field heat loss total was reduced by 45%.

ACKNOWLEDGEMENTS

To members in Faculty of Petroleum Geoscience and Engineering, Universiti Teknologi PETRONAS, thank you for being accommodating.

To my supervisor, Prof. Dr. Mariyamni Binti Awang, thank you so very much for the guidance, motivation, and advice given throughout this project.

To Assoc. Prof. Dr. Ismail Bin Mohd Saaid, Dr. Khalik Mohamad Sabil, Mr. Saleem Qadir Tunio, and Iskandar Dzulkarnain thank you for giving pointers along the way.

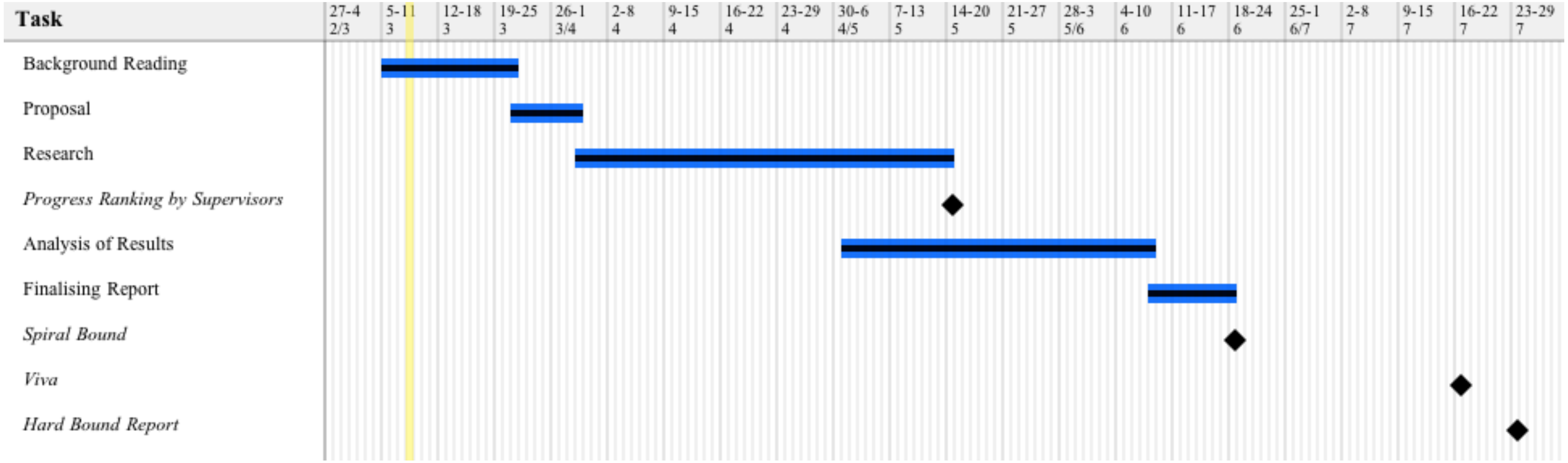
To my sponsor, Brunei National Petroleum Company Sdn. Bhd., thank you very much for providing me this golden opportunity to further my education at University Teknologi PETRONAS.

To Pg. Hj. Md Amirrudin Pg. Hj. Razali, Hazman bin Hj. Junit and Jefrawi bin Dato Kifli, thank you.

To my dear collegues, Adi, Ali, Abdulhadi, Joseph, Lydia, Mariam, Pervez, Putra, Safuan, Shukrat, Sidiq, Timbo, and Zyden, thank you for being there since day one of the course, till the last day of this project.

Last but not least, to my beloved family, thank you for being understanding and supportive.

PROJECT SCHEDULE



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ABBREVIATIONS

BTU	British Thermal Unit
CSS	Cyclic Steam Stimulation
CV	Coefficient of Variance
EM	Electromagnetic
EOR	Enhanced Oil Recovery
ES-SAGD	Solvent with Steam Assisted Gravity Drainage
FHLT	Field Heat Loss Total
FOPT	Field Oil Production Rate
HDCS	Horizontal well, dissolver, carbon dioxide and steam
IFT	Interfacial Tension
IOR	Improved Oil Recovery
IR	Injection Rate
MEOR	Microbial Enhanced Oil Recovery
PI	Production Index
RF	Recovery Factor
TAAD	Thermally Assisted Aquifer Drive
SAGD	Steam Assisted Gravity Drive
SD	Standard Deviation
SOR	Steam Oil Ratio
STOIIP	Stock Tank Oil Initially In Place
SQ	Steam Quality

NOMENCLATURE

k_{rw}	Relative permeability of water (displacing fluid)
k_{ro}	Relative permeability of oil (displaced fluid)
μ_w	Viscosity of water (displacing fluid), cP
μ_o	Viscosity of oil (displaced fluid),cP
M	Mobility
ν	Velocity of displacing fluid
μ	Viscosity of displacing fluid, cP
σ	Interfacial tension between fluid phases
N_c	Capillary number
θ	Contact angle between fluid-fluid interface and solid surface
R_s	Gas oil ratio in liquid phase
R_v	Oil gas ratio in the gas phase
$V_{gas,s}$	Molar volume of gas at surface condition
$V_{oil,s}$	Molar volume of oil at surface condition
MW_{gas}	Molecular weight of gas
MW_{oil}	Molecular weight of oil
$\rho_{oil,s}$	Density of oil at surface condition
$\rho_{gas,s}$	Density of gas at surface condition
μ_{oil}	Oil phase viscosity
μ_{gas}	Gas phase viscosity
μ_{oil}^c	Viscosity of component c in oil phase
μ_{gas}^c	Viscosity of component c in gas phase
A_g	Coefficient default value $4.9402 \times 10^-$
B_g	Coefficient default value of 5.0956×10^{-5}
C_g	Coefficient default value of 2.9223×10^{-6}
D_g	Coefficient default value of 2. 5077
T_c	Temperature, ℃
P_p	Pressure, MPa.

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND

Importance of hydrocarbon production through Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR) is increasing as the world's demand for energy grows. Heavy oil was discovered as early as year 1866 in United States, Nacogdoches [**2**]. In 2005, heavy oil resource was estimated to be 3.80×10^{12} bbl [**3**]. The need for producing heavy crude present also in countries such as Canada, Venezuela, and China has driven research into improving recovery in these challenging scenarios. Classification of heavy oil can be divided into four [**4**] as shown in Table 1 below.

Table 1: Classification of heavy oil [4]

Class		Description	Viscosity	API range
A	Medium Heavy Oil	Mobile at reservoir conditions	> 10 cP < 100 cP	> 18° < 25°
B	Extra Heavy Oil	Mobile at reservoir conditions	> 100 cP < 10000 cP	> 7° < 20°
C	Tar Sands and Bitumen	Non mobile at reservoir conditions	> 10000 cP	> 7° < 21°
D	Oil Shales	Mining extraction		

An area that poses additional challenges to heavy oil recovery is with a thin multi-stacked reservoir. Reservoirs in Oman [**5**], China [**6**], [**7**], [**8**], Thailand [**9**] and Malaysia [**10**] are multi layer stacked reservoirs with heavy oil characteristics. These are 2 to 3 m thick deposits layered on top of one another over a range of depth.

Layering of oil-bearing formation could be explained by cyclic deposition of organic and clay matter [**9**]. An example of such field in this region is Bokor field, Malaysia.

Another example is B92 reservoir in Taobao oil field, China tested through simulation for recovery by steamflooding. However, this method of recovery did not meet commercial criteria. Factors affecting performance of steam stimulation in that field included [**6**]

a. large heat losses in thin oil bearing layers with thickness of 2.5 m and lower,
b. water coning effects,
c. steam injection pressure constrains due to shallow depth of reservoir, and
d. large sand production in unconsolidated formation.

Other complications [**1**] such as offshore location, consolidation of the reservoir, high cost incurred and high water cut level are some of the additional factors contributing to the existing difficulty of recovering hydrocarbon from the thin multi-stacked formation.

Various thermal recovery methods were explored to enhance recovery in heavy oil reservoirs, with steam injection being the most common approach [**11**]. However, efficiency of steam injection is an on-going research up till today. Main problematic areas in implementing steam flooding are thermal efficiency [**6**], [**12**] and early steam breakthrough [**7**].

To increase the efficiency of steamflooding, analysis on different reservoir characteristics and production configurations were conducted to improve thermal and sweep efficiency. This includes experimental and simulation study of production on different spot patterns [**13**], the use of smart injection and production wells [**14**], rate and quality of steam injection, solvent, and steam injection [**15**].

1.2 PROBLEM STATEMENT

Large heat losses due to thin layers with average thickness of 2.5 m and lower was reported by Liu *et al.* [**1**] as one of the factors resulting in non-commercialization for steamflooding. Reduction in heat loss and increase in efficiency of steam injection would make steamflooding more attractive choice, especially for an offshore environment. An improved understanding on reservoir properties in relation to the type of recovery is necessary.

1.3 OBJECTIVES

First objective of the project is to build a compositional 3-D model, incorporating thermal properties. The second objective is to study and quantify the effect of changes in the following reservoir parameters for a multi layer reservoir,

a. vertical heterogeneity,
b. oil viscosity,
c. sand layer thickness,
d. frequency and thickness of shale, and
e. porosity values.

The third objective aims at increasing the recovery in a multi-layer reservoir by investigating multiple injection strategies.

1.4 SCOPE OF STUDY

Numerical approach is implemented to investigate changes in geological properties of a multi-layer reservoir with the use of “Schlumberger ECLIPSE 300”. A 3D-model consisting five units of formation, where each unit consists of a permeable and impermeable layer, will be adapted. Data of reservoir are closely modeled to Bokor field. Viscosities of 10 cP at 75°F and 63 cP at 75°F will be investigated. Only one injector and producer will be used.

CHAPTER 2

LITERATURE REVIEW

2.1 MULTI-LAYERED RESERVOIR

Reservoirs in Oman [**5**], China [**6**] [**7**] [**8**], Thailand [**9**], Malaysia [**10**] and Brunei [**16**] display multi-layer stacked reservoir characteristics. Pru Kartiam reservoir onshore of Thailand has net-to-gross thickness of 15% to 20% only over a sand body height of 700 m [**9**]. Consolidation, degree of heterogeneity, initial water saturation, thickness of pay zone, and location of the field are some of the factors that influence the choice of recovery.

Fluvial and deltaic deposit in continental environment results in multi-layer sandstone reservoir. Layering of oil-bearing formation could be explained by cyclic deposition of organic and clay matter [**9**]. An example of a such reservoir is Sarto reservoir with multi-layer sandstone fluvial and deltaic deposit at a depth of 1000 to 1200 m, permeability of 500 to 2000 mD, porosity of 20 to 30%, surface oil viscosity of 50 to 100cP at 50°C (122°F), wax content of 25 to 30% and a freezing point of 30 to 35°C (86 to 95°F) [**8**].

2.1.1 Fluvio-Delta Deposit

Fluvial deposits are due to flow of a river towards a lake or sea [**17**]. From the level of energy possessed by grains, these grains will settle at different points along a river. Grains deposited further away from the source will be finer, has a more rounded particle shape, and are more sorted. Porosity and permeability are dependent on grain size and sorting.

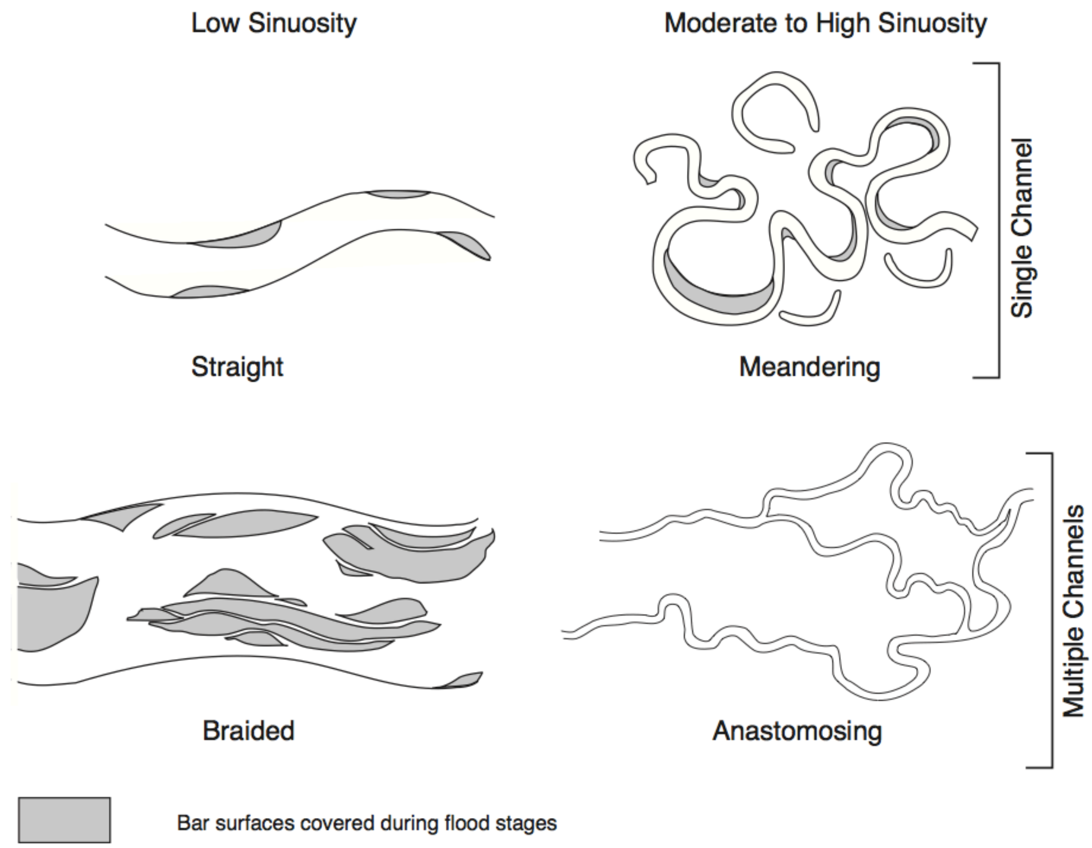

Figure 1: Four classifications of fluvial channel [17]

Fluvial channels are generally classified into four according to their planar shape: straight, braided, meandering and anastomosing. These differences are illustrated in the Figure 1 above.

Fluvial deposit reservoirs generally result in a channel belt of sandbodies, controlled by its stacking pattern [**17**]. Eight basic types of 'architectural elements' classified by Miall in 1985 shown in Figure 2 [**17**] are for structuring a reservoir model [**17**].

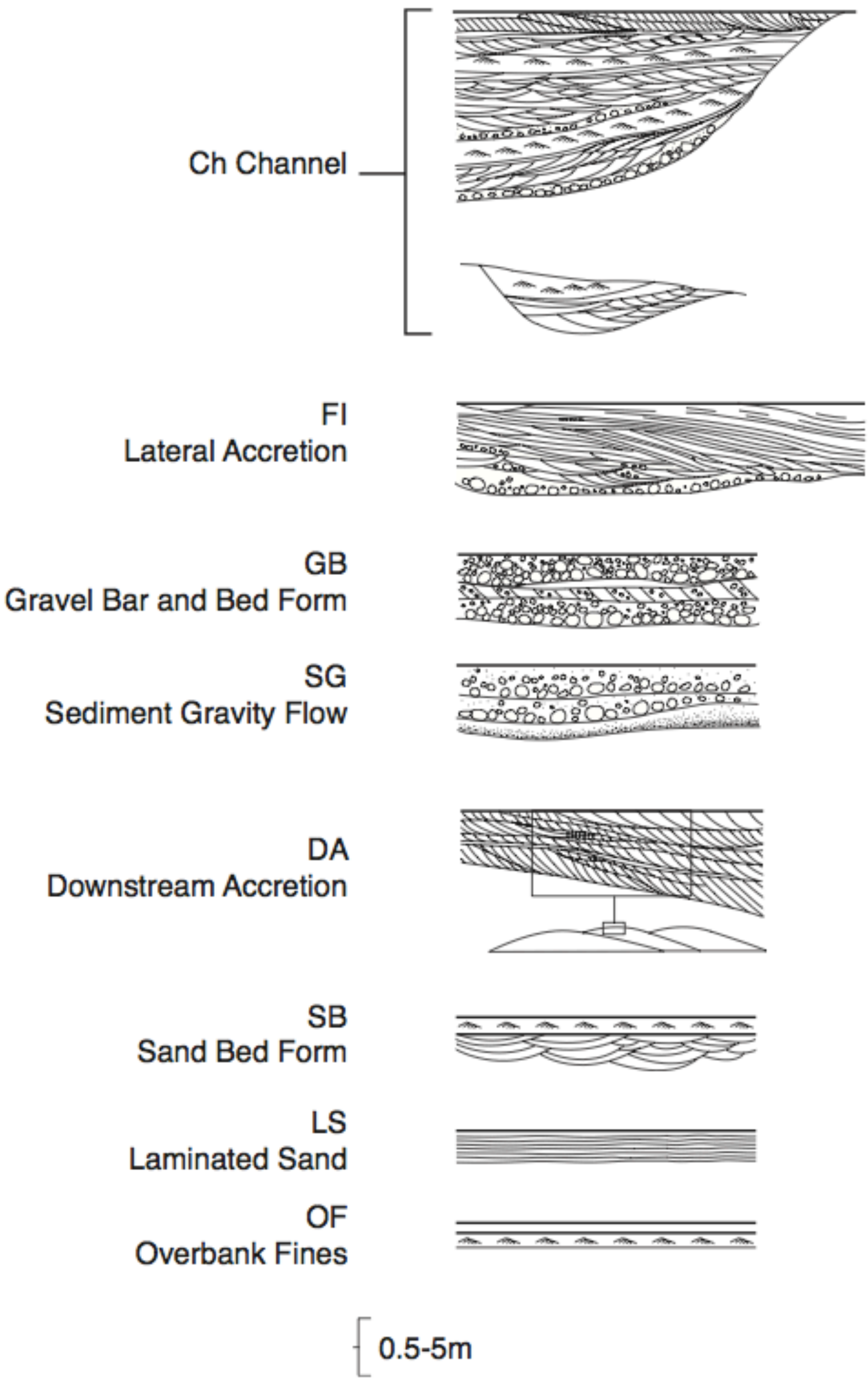

Figure 2: Laminated sand and seven other basic architectures [17]

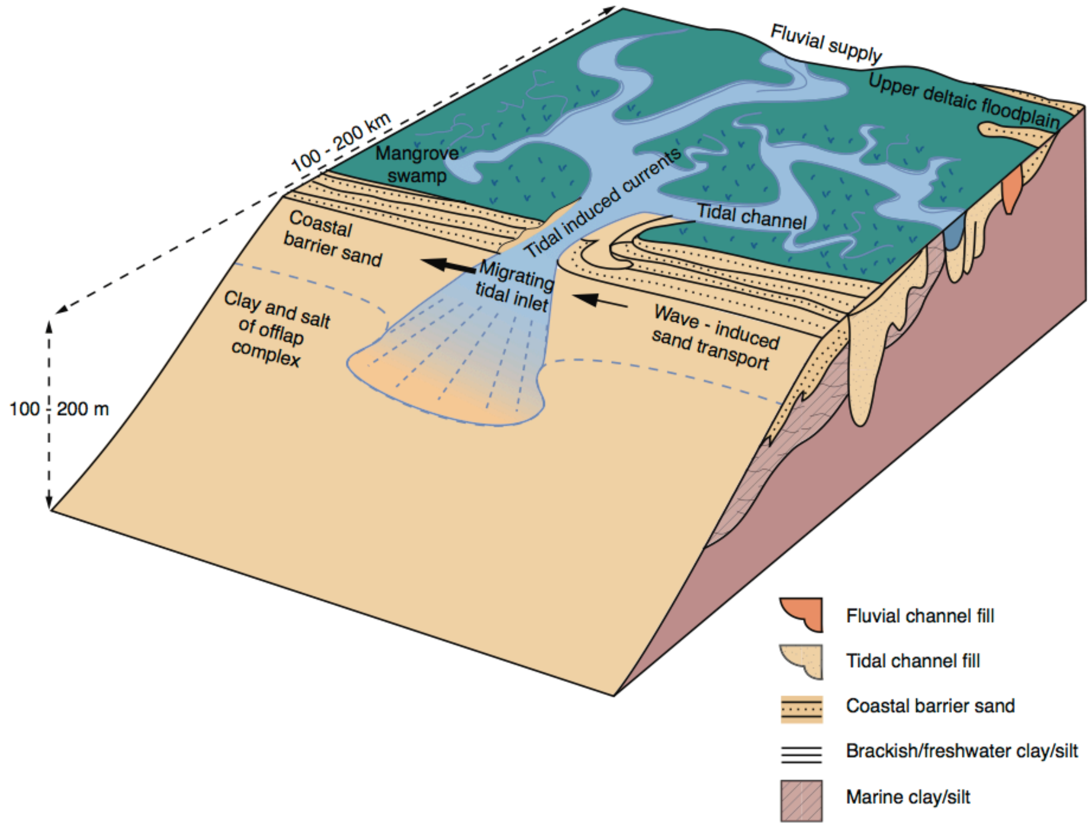

Figure 3: Niger Delta, with fluvial, tide and wave influence [17]

Location of a fluvio-delta deposit occurs at the mouth of a river is as shown in the Figure 3 [**17**] above. Through analysis and studies conducted, examples of several different types of fluvial dominated deltaic deposit are show in Figure 4 [**17**]. The type of reservoir investigated in this project is boxed in red.

An example of such reservoir is Bokor Field, located 45 km northwest offshore Lutong, Sarawak in the Baram Delta region. This will discussed in more details in Section 2.3 [**18**].

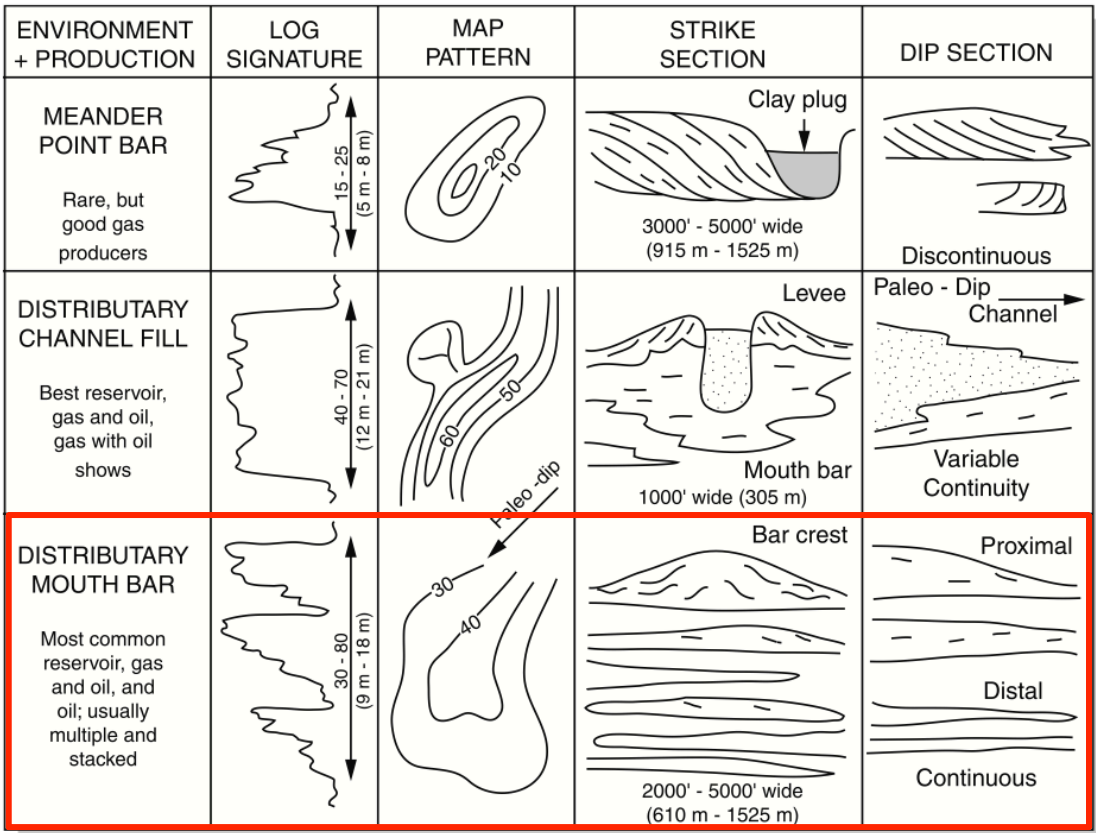

Figure 4: Environment and corresponding reservoir [17]

2.1.2 Heterogeneity

Base on data from Texan reservoirs, Tyler and Finlay categorized effects of different architecture in terms of vertical and lateral heterogeneity, recovery and drive mechanisms [**17**]. Investigation of multi-layer reservoir falls in a section with high lateral heterogeneity and low vertical heterogeneity.

Lateral Heterogeneity

Vertical Heterogeneity	Low	Moderate	High
Low	Wave-dominated delta Barrier core Barrier shore face Sand-rich strand plain	Delta-front mouth bar Proximal delta front (accretionary) Tidal deposits Mud-rich strand plain	Meander belt• Fluvially dominated delta• Back barrier•
Moderate	Eolian Wave-modified delta (distal)	Shelf bars Alluvial fan Fan delta Lacustrine delta Distal delta front Wave-modified delta (proximal)	Braided dtream Tide-dominated delta
High	Basin-flooring turbidites	Coarse-grained meander belt Braid delta	Back barrier• Fluvially dominated delta• Fine-grained meander belt• Submarine fans•

• single units
• stacked systems

Figure 5: Variation in heterogeneity with different systems [17]

2.2 HEAVY OIL

Physical and chemical properties of fluids present in the reservoir affect the type of recovery implemented. Presence of heavy oil in reservoirs would generally require thermal recovery to reduce its viscosity, hence easing flow of hydrocarbon.

2.2.1 Viscosity

Viscosity measures the ability of a particular fluid to flow. Correlation derived by Beggs and Robinson, and Egbogah and Ng related temperature and pressure changes to viscosity of oil. Ability to reduce viscosity of heavy oil is dependent on its initial viscosity. Through experiments, high oil viscosity of 100 cP at 50°C in Sarto reservoir was decreased to 2 cP, similar mobility to water, when oil temperature was 200°C [**8**].

For ultra heavy oil reservoir, Sun *et al.* [**19**] applied a combination of horizontal well, dissolver, carbon dioxide and steam (HDCS) to improve production. Increment of recoverable reserves reached 12.71 million tons in Wangzhuang and Shanjiasi oilfield in Shengli petroleum province [**19**]. This further enforces the need to look into various strategies of enhancing recovery implemented together or in succession for improving recovery.

2.2.2 Composition

Asphaltene content in heavy oil is usually higher. These are chemically altered organic compounds that complicate production and are amorphous, bituminous, solid material precipitating from crude [**20**].

2.3 BOKOR FIELD

An example of such multi-layered field in this region is Bokor Field located offshore Lutong, Sarawak, Malaysia [**18**]. With constant improvement in technology and availability of new data, over 30 years, STOIIP increased from 100 MMSTB to 800 MMSTB [**18**].

2.3.1 Geology

Baronia-Betty-Bokor anticinal trend created Bokor structure, which has main hydrocarbon accumulation on upthrown side of Fault-9 [**18**]. Between 1000 ft and 6300 ft, alternating shallow marine sand and shale with lateral continuity has been identified. Vertical heterogeneity was interpreted from shale layers thickness and frequency variations [**18**]. This is shown in Figure 6 [**18**] below.

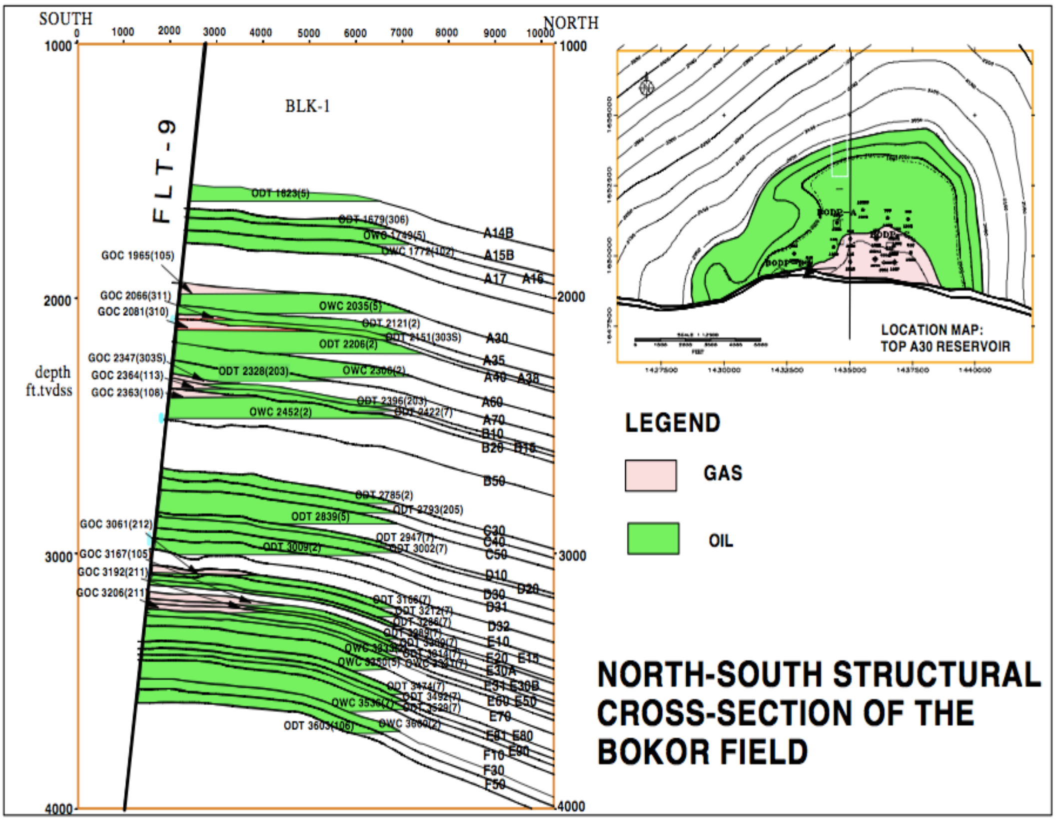

Figure 6: Hydrocarbon accumulation at upthrown side of growth Fault-9 with almost flat crest and flanks dipping from 2° to 6° [18]

2.3.2 Properties

Bokor field posses the following properties for shallow and deeper sands [**21**] [**22**].

a. Range of porosity between 15 to 32%,
b. Permeability between 50 to 4000 mD,
c. Oil gravity of 19° to 22° API at reservoir depth of 1500 to 3000 ftss (shallow reservoir) and 37° API at deeper reservoir (6300 ftss),
d. Viscosity of oil (2 cP to 10 cP) from shallow reservoir, and
e. Dead oil viscosity 230 cP.

2.3.3 Challenges

Difficulties faced with developing this field are [**18**]

a. shallow reservoirs with depth of 2000 ftss,
b. unconsolidation of sand layers,
c. thinly stacked reservoir,
d. heavy crude oil, and
e. uncertainties in structure of the field.

2.3.4 Development

In 2001, it was reported that pilot project for microbial enhaned oil recovery (MEOR) was implemented in this field after satisfying basic screening criteria, with the expectation of viscosity reduction and hence improvement in recovery [**21**]. Monitoring pilot project at this reservoir for 5 months indicated an improvement in recovery by 47%. However, viscosity of oil tested did not reduce significantly as shown in Figure 7 relative to pre-treatment as cyclic alkenes and aromatics were left. Biodegration resulted in a shift of oil property from paraffinic to naphtenic-aromatic. Microbes cleaned up damaged skin formation, reducing skin factor, thus improving Productivity Index (PI) [**21**].

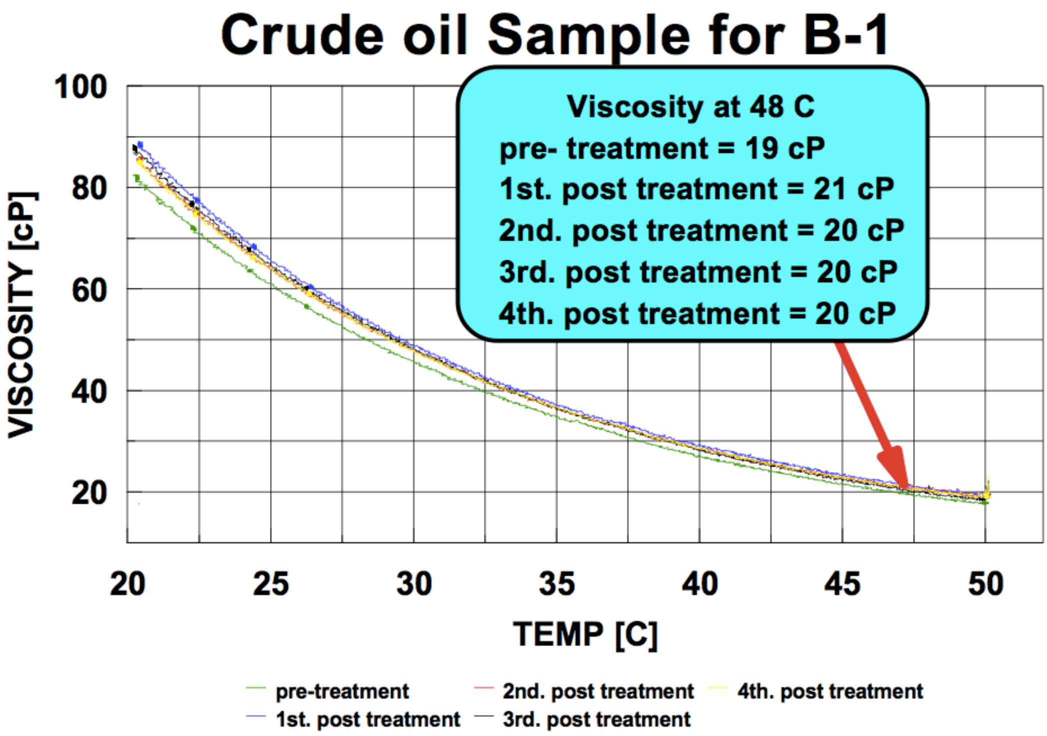

Figure 7: Crude oil viscosity at location B-1 of Bokor field [23]

2.4 THERMAL RECOVERY

Types of thermal EOR include cyclic steam injection, steam drive, steam assisted gravity drainage (SAGD), solvent with SAGD (ES-SAGD) and in-situ combustion. Other forms of supply of energy into the formation include methods such as electromagenetic (EM) method. This project focuses on steamflooding.

2.4.1 Energy Supply

Energy cannot be created or destroyed. It can only be transferred from one body to another. Heat is transferred from one medium to another through conduction, convection, and radiation. Heat loss in a well segment and between segments have been studied and replicated in simulators.

Efficient supply of thermal energy to the reservoir is an important factor contributing to the success of steamflooding. The industry has come up with different ways of heat supply to the reservoir including in-situ combustion and steam assisted gravity drainage (SAGD). Lombard *et al.* [**12**] reviewed the use of high vacuum insulated tubing in the future especially for depths of around 1800 ft to 2000 ft. This method of thermal insulation was reported to be 98.4% thermally efficient [**12**]. It could be modified and tested in thin multi-layered reservoirs.

EM method of thermal energy supply is non-steam based and more environmentally friendly [**24**]. Viscosity reduced from 3062 cP by 97% to 98.9 cP [**24**], and with the same input of energy. When compared with cyclic steam stimulation (CSS) method, EM method was more efficient. EM method of thermal energy supply to thin multi-stack reservoir should be analyzed.

2.4.2 Effect of Geological Factors

Review on effect of depth, thickness and heterogeneity of layers on recovery are covered in the following sub sections.

2.4.2.1 Depth and Thickness

Depth of the reservoir affects the type of steam injection that can be used. Injection of superheated steam could reach a shallower depth compared with steam that has 40% quality [**25**]. Thin reservoirs are usually more challenging to produce than reservoir thick reservoir.

2.4.2.2 Heterogeneity

Heterogeneity of a formation affects the type of injection strategy that should be used. Zan *et al.* [**7**] reported that combination of injection and production well differed in a homogeneous reservoir to a heterogeneous reservoir. In a heterogeneous formation, the distribution and size of shale layers affects recovery. Steam will disperse unevenly, hence resulting in a poor distribution of heat [**9**].

Simulation study carried out by Ashrafi *et al.* [**15**] modeled a core with high permeability steak through the middle. Lowering thickness of this high permeability zone increased productivity. Recovery also increases as permeability to shale barriers increases. In a way, this study resembled a small-scale study of layered reservoir.

2.4.3 Properties of Steam

Quality, temperature and additives injected with steam affect performance of steam injection. This is elaborated further in the following subsections.

2.4.3.1 Steam Temperature

The main advantages of using superheated steam are high specific heat enthalpy, and ability of altering wettability of rock [**25**]. Wu *et al.* also reported that the pilot test of CSS with superheated steam performed better than wet steam. Water cut reduced more than 10% when superheated steam was used. However, when the well heat loss was modeled, superheated steam reached a shallower depth in comparison with wet steam with 40% quality. Out of the six cases tested, the case with two cycles of CSS steamflooding followed by natural depletion proved to be the best option economically and production wise.

By using data from Athabasca heavy crude, optimum temperature of steam reported was at 200 ℃ [**15**]. Taking incremental recovery with increasing temperature optimized this value. Similar test can be carried out to compare optimum steam temperature for different types of heavy crude.

2.4.3.2 Steam Quality

Steam quality defines the ratio of steam present in fluid injected. Quality of steam is more significant in a system that has vertical injector and a horizontal producer in thin, shallow reservoir [**7**]. For Athabasca heavy crude, it was reported that optimum steam quality was 85% [**15**].

2.4.3.3 Additives

Steamflooding carried out in recent years are usually injected together with additives to improve recovery of the reservoir, with the condition that they can tolerate high temperatures and will not have a negative impact on recovery. Stringent screening and tests are usually implemented to propose optimum type of steam and its additives, before conducting a pilot test.

Additives improve recovery by mitigating steam override effect and improving sweep efficiency. Ashrafi *et al.* [**15**] reported more solid asphaltene precipitation occurred with lighter n-alkanes when mole fraction of solvent was increased.

Propane:steam mass ratio of 4:100 accelerated production of oil, due to further reduction in viscosity of oil [**14**]. Steam zone in this combination is increased. Effect of propane on oil recovery is affected by the rate at which propane is injected. It was believe that time is needed for propane to react with oil. Recovery was increased by 21.8% in comparison to recovery with steam only. This approach of recovery with propane could be tested for thin multi layered reservoir.

Reduction in steam oil ratio (SOR) reduces cost of steamflooding. A recent research with the use of nickel nanoparticles was able to increase recovery by 10% [**26**]. This is has yet to be optimized. However, nickel also acts as a catalyst. A number of factors such as rate of injection and suspension of particles will affect the performance of this catalyst [**26**]. Other organic chemicals, such as alcohols [**27**] should also be tested to study their performance upon injection with steam.

2.4.4 Steamflooding strategies

Combinations of different types of wells to optimize production are usually carried out experimentally and by simulation. Here, emphasis is put on reviewing numerical simulation studies conducted.

2.4.4.1 Patterns

Improved inverted 9-spot patterns were used in numerous experiments [**7**], [**28**], [**8**]. Other patterns used are inverted 5-spot and 7-spot patterns. Type of patterns used affects the choice of ideal mobility ratio between displacing and displaced fluid. Wang [**13**] reported that for a favorable mobility ratio of less than 0.3, a 5-spot pattern gives a better sweep efficiency than a staggered line drive. This is due to changes in streamlines and pressure distribution resulting from different mobility ratios [**13**]. Comparison of different steam injection patterns in thin multi layered reservoir could be studied.

2.4.4.2 Injection and Production Wells

Configurations investigated by Zan *et al.* [**7**] were vertical injection-vertical production well-group, vertical injection-horizontal production well-group, and horizontal injection-vertical production well group. If a reservoir is shallow, thin, has argillaceous interbed with extra heavy oil, it was reported that among the three combinations of horizontal and vertical producers, combination of vertical injector and vertical producer gave the best recovery [**7**]. However, if the formation was homogeneous, then a vertical injector with a horizontal producer was reported to give the best recovery.

Mamora and Sandoval [**29**] introduced a novel method to improve oil production from a mature oil field. Vertical injector with a smart horizontal producer, where the producer was divided into three sections after thorough research, was implemented as shown in Figure 8 [**29**]. With smart wells, amount of oil in contact with steam was increased, thus enhancing recovery. This was carried out with the configuration where initially, all the three segments were opened. Studying the effect of different steam quality injected could extend this study to improve recovery.

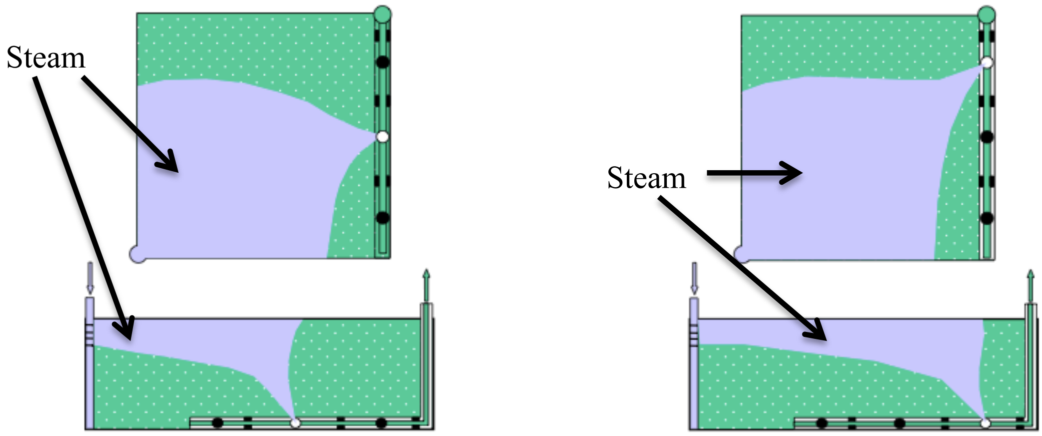

Figure 8: Vertical injector with a 3 segment, smart horizontal producer [29]

Wu *et al.* [**8**] mentioned that waterflooded reservoir of depths larger than 800 m will have to divide the steamflooding process into two. The first is where CSS is implemented for two years to decrease pressure to 8 MPa. The second stage is where steamflooding is carried out for 8 years.

In a multi-layer reservoir with varying permeability layers, control of waterflood to produce heavy oil was achieved by applying mechanical and chemical controls [**5**]. Six conformance control methods were proposed and tested. Research with steamflood can be conducted to study if these methods are applicable.

Effect of steam override is still a problematic issue although different combinations of injection and production wells were experimented. Although the issue has not been eradicated, it has been mitigated through different methods employed to improve sweep efficiency.

2.4.5 Challenges

Complications encountered for steamflooding include location of the reservoir to macroscopic and microscopic related concerns.

2.4.5.1 Location

In Malaysia, back in 1986, a screening study was conducted by Shell to look into potential of EOR [**23**]. It was suggested that the best candidate is thermal recovery. However, it was not taken into consideration. Reasons highlighted were well spacing and offshore environment [**23**].

2.4.5.2 Mobility

Main problem of using steam is rapid breakthrough of injected steam. The main reason behind this is due to difference in density between steam and heavy oil, and also permeability differences between layers. An approach to look into this displacement problem is through the control of mobility ratio. For example, if water is displacing oil, mobility ratio is given by

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} \tag{2.1}$$

where

k_{rw} = Relative permeability of water (displacing fluid),
k_{ro} = Relative permeability of oil (displaced fluid),
μ_w = Viscosity of water (displacing fluid), and
μ_o = Viscosity of oil (displaced fluid).

With mobility ratio of less than 1, displacement front will be stable. If this can be achieved, it will lead to a good sweep, thus a good recovery factor. By looking at **(2.1**, a ratio of less than 1 can be achieved by reduction in viscosity of oil and increasing viscosity of displacing fluid. Relative permeability values of displacing fluid and residual oil can also be altered by the changing interfacial tension values between those two fluids. Generally, polymers increase viscosity of displacing fluid, leading to a lower mobility ratio.

2.4.5.3 Capillary number

Capillary number is defined below with the following equation [**30**],

$$N_c = \frac{\nu\,\mu}{\sigma\, cos\theta} \tag{2.2}$$

where

ν = Velocity of displacing fluid,
μ = Viscosity of displacing fluid,
σ = Interfacial tension between fluid phases, and
θ = Contact angle between fluid-fluid interface and solid surface.

Significant effect of reducing N_c can only be observed through recovery if N_c is reduced by an order of four to six times [**30**]. Changes in σ and $cos\theta$ will affect N_c. However, it is more common to reduce interfacial tension values to very low values for enhancing oil recovery with the use of surfactants.

2.4.5.4 Residual Saturations

Kumar and Do [**31**] studied the effects of end points saturations in steamflood performance on heavy oil reservoir. In a water-oil system, when comparing effect of irreducible water saturation and residual oil saturation to water, the former has a larger effect on performance [**31**]. For that system, it was also concluded that dependency of end point saturation of residual oil water saturation on temperature is small [**31**]. Production rates after steam breakthrough is mostly governed by gas-oil relative permeability.

2.5 GAS INJECTION

Types of gas injected to enhance oil recovery can be hydrocarbon or non-hydrocarbon, miscible or immiscible with fluids. Examples of non-hydrocarbon gas injected are air, CO_2 and N_2.

For Bohai heavy oil field offshore China, steam and flue gas injected made steam injection offshore condition possible through a more portable steam injector. CO_2 and N_2 injected decrease heat loss of steam to a certain extent. It was proposed that flue gas and steam should be coinjected at 200℃ [**1**]. Applicability of this technology could be studied for thin multi-layered reservoirs.

2.6 ECONOMIC ANALYSIS

Feasibility of a project depends on economic outcome as well. In 1986, after the collapse of oil price, it was no longer commercial to produce from thin heavy oil reservoirs at Morgan Field in Canada from Lloydminster and Sparky sands [**32**].

Table 2 [**23**] shows cost incurred by implementing different EOR processes in Malaysia as reported by Hamdan *et al.* [**23**] in 2005. The use of micellar surfactant was the most costly process.

Table 2: EOR cost database [23]

Process	Cost, US$/bbl of incremental oil	
	Injectant Only	Total Process*
Thermal - Steam - Purchased fuel	 3 - 5 4 - 6	 5 - 7 7 - 10
Gas - CO_2	 5 - 10	 12 - 20
Chemical - Surfactant (Micellar) - Alkaline - Surfactant/Alkaline/Polymer - Polymer	 10 - 20 ~7 2 - 7 1 - 5	 20 - 30 ~19 10 - 17 ~2 - 7

2.7 NUMERICAL SIMULATION

Numerical simulation model is a grid block made up of many interconnected blocks. To represent a reservoir, reservoir fluids and reservoir description are integrated into these blocks, which remain constant within a block.

2.7.1 Model

Types of model reviewed in this section are streamline model and grid model.

2.7.1.1 Streamline Model

The use of streamline simulation in steam floods by Zhu, Thiele and Gerritsen [**33**] has shown that they were able to reduce cost of computing, whilst gaining connectivity information valuable to reservoir engineers. Simulator used in this case was CMG STARS. Assumptions made in their study were that there are water and non-volatile oil are present [**33**].

2.7.1.2 Grid model

An improvement in displacement pattern due to grid orientation was reported when Gonzalez, Bashbush and Rincon tested the use of Perpendicular Bi-sector (PEBI) grids in "Schlumberger ECLIPSE" as shown in Figure 9 [**28**].

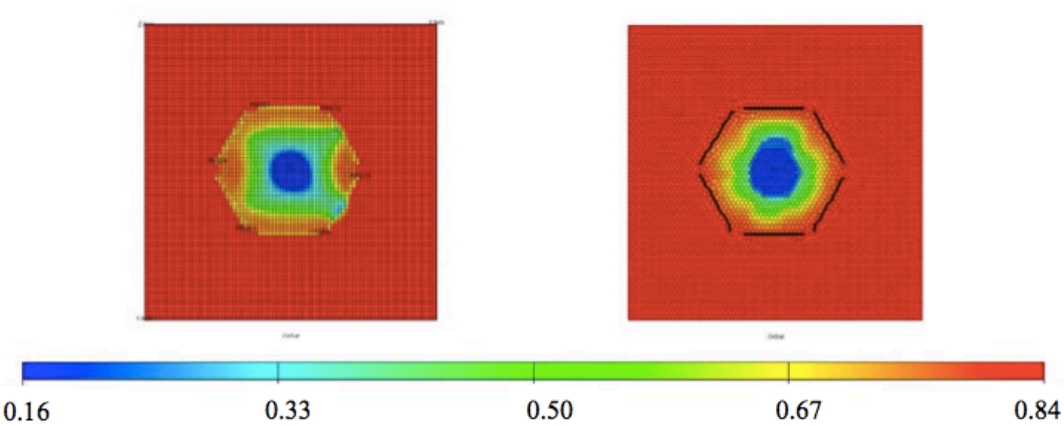

Figure 9: Difference between displacement pattern in Cartesian 9-point Finite Difference Operator and (left) and PEBI grid (right) [28]

This grid then became the basis of other tests conducted. It was also mentioned that rate at which steam was injected was of great importance [**28**]. Analyzing sensitivity base on solvent or chemical injection with steam injection could extend this research further.

Inconsistent numbers of grid blocks were used when numerical simulation test was carried out by Zan et *al.* [**7**]. For vertical injection-vertical production configuration, 610 active grid blocks were used. This was approximately 10 times less than the number of grids used in a combination of vertical and horizontal wells.

A 20×10×11 grid block model used to represent a sandstone core of 1cm in x-direction and 0.33588 in both y- and z-directions. This core has a 1mm thick horizontal layer as a high permeability layer through the core [**15**]. Studies were then carried out by varying the thickness of the high permeability layer, type of steam injected and introducing shale barriers into the model. A large scale study base on this core study can be carried out to incorporate the effect of temperature difference, due heat loss to the along wellbore, such as that in a multi-stacked reservoir.

"Schlumberger ECLIPSE" has corner point geometry and conventional block-center geometry options that handle up to 4 phases in the simulator. This includes oil, gas, water and solid phases. It can also be run in three modes [**34**],

a. By using K-values, a function of pressure and temperature, for defining equilibrium in live oil model,
b. Dead oil model for non-volatile hydrocarbon components, and
c. Black oil model.

This software will be used for simulation in this project.

2.7.2 Thermal Properties

Operating conditions of thermal option with "Schlumberger ECLIPSE" is between 1 and ~100 atmospheres (1 to ~100 bar) and range of temperature from ambient to ~700°F (~370°C) [**34**].

Thermal properties are dependent on the mineral composition of a particular rocks. Its thermal capacity can be calculated simply by weighted average of thermal capacities of mineral components. An example of such calculation is shown in Table 11 [**35**].

Table 3: Rock unit thermal capacity calculation for inhomogeneous sample [35]

Lithology	Thickness (m)	Mineral components	Mineral density	Mineral component weight %	Mineral component volume % within layer	Thermal capacity (J/cm^3/°K)	Thermal capacity (kJ/cm^2/°K)
Shale	30						
	25.9	Clay	2.7		86.3	2.16	5.59
	2.9	Quartz	2.648		9.7	1.96	0.57
	1.2	TOC (kerogen)	1.2	2	4.0	1.8	0.22
Limestone	67						
	63.6	Calcite	2.745		95.0	2.24	14.25
	3.4	Dolomite	2.84		5.0	2.47	0.84
Sandstone	3						
	1.8	Quartz	2.648		60.0	1.96	0.35
	0.6	Feldspar	2.6		20.0	1.63	0.10
	0.6	Granite	2.635		20.0	2.33	0.14
Rock Unit	100		2.712			2.167^a 2.206^b	22.06

Equations used in thermal options have three main additions when compared to solving for a compositional simulation. These are [**34**]

a. Presence of water component in gas phase,
b. Presence of water component in water phase, and
c. Properties dependent on temperature.

Thermal option utilizes K-values to obtain equilibrium and densities, viscosities and enthalpies for each component in each phase instead of using equation of state to determine thermodynamic properties [**34**]. Function of K-values is to determine distribution of volatile components between oil and gas phases [**34**]. Heat capacity, thermal conductivity, thermal transmissibility and heat conduction are definable quantities in "Schlumberger ECLIPSE".

K-values explained in "Schlumberger ECLIPSE" for thermal options were reported to be base on Crookston, Culham, and Chen and Coats, if keyword KVCR was used. In thermal mode, oil phase viscosity can be calculated through

$$log\, \mu_{oil} = \frac{1}{F + R_s} \cdot \left(F \cdot log\, \mu_{oil}^{oil} + R_s \cdot log\, \mu_{oil}^{gas}\right). \qquad \textbf{(2.3)}$$

Similar equation can be applied to calculate gas phase viscosity as

$$\mu_{gas} = \frac{1}{F \cdot R_v + 1} \cdot \left(F \cdot R_v \cdot \mu_{gas}^{oil} + \mu_{gas}^{gas}\right), \qquad \textbf{(2.4)}$$

where variables have the following description:

R_s = Gas oil ratio in liquid phase,
R_v = Oil gas ratio in the gas phase,
μ_{oil} = Oil phase viscosity,
μ_{gas} = Gas phase viscosity,
μ_{oil}^{c} = Viscosity of component c in oil phase, and
μ_{gas}^{c} = Viscosity of component c in gas phase.

These viscosity values can be input in tabular form. Other methods for calculating specific component viscosity is through any of the correlations stated below [**34**]:

a. ASTM correlation,
b. Andrade formula,
c. Vogel formula, and
d. Logarithmic formula.

Steam viscosity is defined in "Schlumberger ECLIPSE" by the following equation:

$$\mu_g = A_g + B_g T_c + C_g P_P^{D_g}, \quad \textbf{(2.5)}$$

where the default values of constants and their respective meanings are stated below.

μ_g = Steam viscosity,
A_g = Coefficient default value 4.9402 × 10^{-3},
B_g = Coefficient default value of 5.0956 × 10^{-5},
C_g = Coefficient default value of 2.9223 × 10^{-6},
D_g = Coefficient default value of 2.5077,
T_c = Temperature in °C, and
P_p = Pressure in MPa.

Current limitations with Thermal option "Schlumberger ECLIPSE" include [**34**]

a. molecular diffusion,
b. transport coefficients modeling mobility of each component,
c. non-Darcy flow,
d. optimization of workflow, and
e. surface tension effects.

Time (Δt) and spatial (Δx) discretization due to gridding could lead to error in numerical dispersion. The degree of this error is due to several factors including type of fluid injected [**36**].

2.8 EXPECTED RESULTS

Results expected in this project are:

a. For all cases, steam injection should increase recovery compared with water injection, as viscosity is reduced, fluid will flow with more ease,
b. High permeability layers are expected to have an earlier breakthrough compared to low permeability layers,
c. With lower oil viscosity, recovery is expected to be higher.
d. Thicker sand layers are expected to have a better recovery than thin layers,
e. Frequent occurrence of thick shale layers would reduce thermal efficiency for steam injection, leading to a lower recovery,
f. Injection of CO_2 will help in viscosity reduction and recovery is expected to increase.

CHAPTER 3

METHODOLOGY

3.1 SIMULATOR

This study involves the use of thermal options. “Schlumberger ECLIPSE 300” simulator enables thermal studies with modeling compositional oil. Field units is used in this model.

3.2 MODEL

Suitable model with the appropriate parameters and sufficient grid size is required for investigating different cases proposed. Bokor field data and “THERM13A.DATA” were used to construct a suitable model for investigation. This data file provided with “Schlumberger ECLIPSE” software was a based on an intercompany investigation of scenarios including steam injection models, with 3 components of oil [**37**]. In this study, majority of parameters used such as viscosity of oil and heat conductivity of rocks was extracted from this example. Assumptions made in developing the model includes

a. One rock type throughout the reservoir,
b. 0° inclination angle of the reservoir,
c. Aquifer support is absent in the model,
d. Saturation properties obtained from “THERM13A.DATA”,
e. Oil viscosity range from Bokor field, and
f. Range of thickness of layers according to properties reported for Bokor field.

3.2.1 Reservoir Grid

A $20\times20\times20$ sized Cartesian block-centered grid model will be used for all simulations. Other properties for Base Case grid model are tabulated below.

Table 4: Dimensions of model

Parameters	Values
Length in X, Y, Z direction (ft)	600 x 600 x 100
Porosity of sand layers (%)	30
Permeability of sand layers (mD)	1000
Initial temperature of reservoir (°F)	125
Sand layer thickness (ft)	10
Shale layer thickness (ft)	10

3.2.2 Oil Viscosity

Compositional model was used to describe the paraffin series of oil. Oil Type A and B with a viscosity of 10cp and 67cp at 75°F respectively will be modeled.

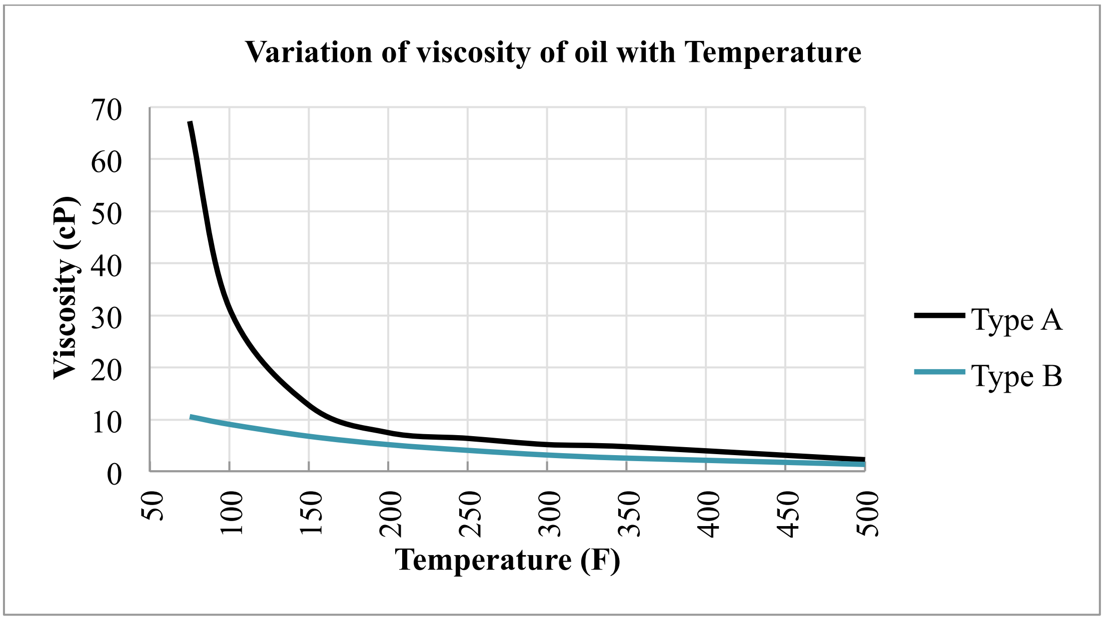

Figure 10: Viscosity of Type A and B oil

3.2.3 Relative Permeability

Relative permeability of oil to water for Type A oil are shown in the following figure.

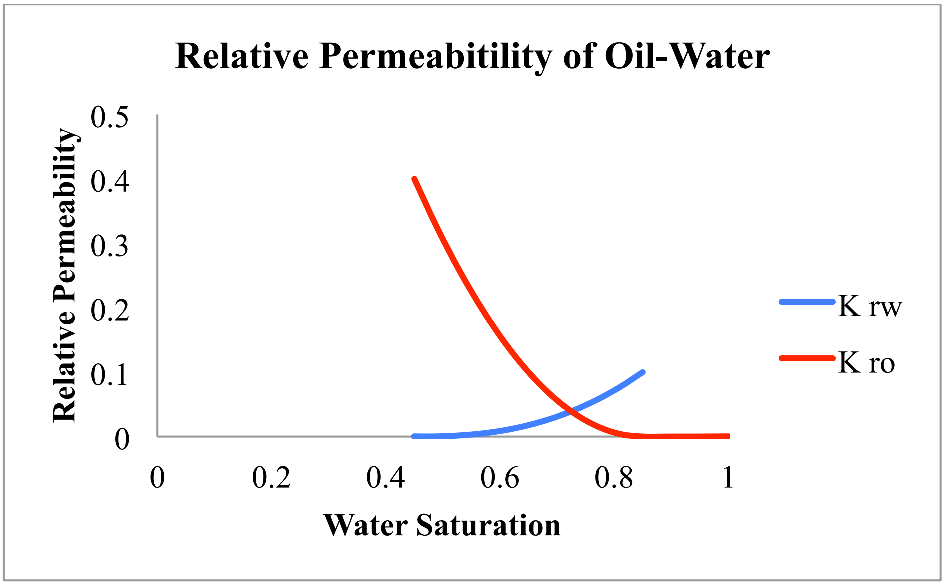

Figure 11: Relative permeability of Oil-Water System

3.2.4 Thermal Data

Heat capacity and thermal conductivity data are stated in Table 5 below.

Table 5: Thermal properties of model

Parameters	Values
Rock heat capacity (BTU/ft^3/°F)	35
Thermal conductivity of rock and fluids (BTU/ft^3/day/°F)	24

3.3 BASE CASE

Base case (BC) of this experiment is a 3D cross-section model with;

a. Dimensions of $20 \times 20 \times 20$,
b. One injector (at 1,1), one producer (at 20,20),
c. Heavy oil viscosity of 67.3 cP at 75°F,
d. 5 units, each unit comprise of a layer of sand (10 ft) and layer of shale (10 ft),
e. Well completed only at sand layers,
f. Porosity values for shale is 0%,
g. Surface injection rate of 300 stb/day, and
h. Permeability of 1000mD.

The model is illustrated in Figure 12. Thermal keywords used are tabulated in Appendix A, and simulation code for Base Case model is included in Appendix B.

From the Base Case, two groups of analysis will be done. The first analysis is carried out to study variation in five different parameters and sensitivity of four geological parameters. The second part of the project will investigate different methods to improve production of the reservoir.

(a) A unit consisting of a sand and shale layer

(b) 20 x 20 x 20 grid representing Base Case model consisting 5 units

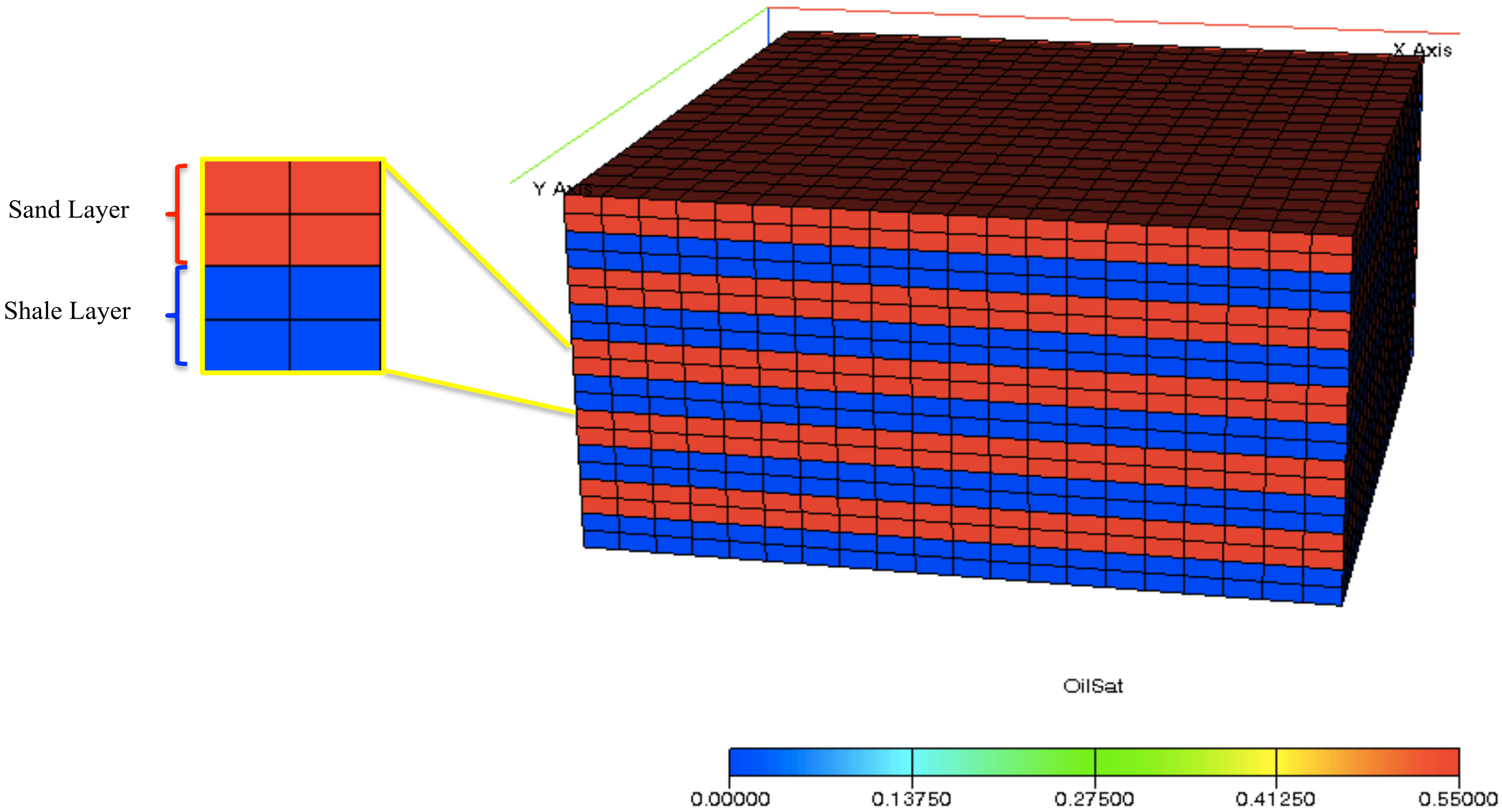

Figure 12: Reservoir model Base Case

3.4 RESERVOIR PROPERTY VARIATION

Five cases investigated the first section of this project are

a. **Case 1**: Heterogeneity of sand layers,
b. **Case 2**: Oil viscosity,
c. **Case 3**: Sand layer thickness,
d. **Case 4**: Frequency and thickness of shale, and
e. **Case 5**: Porosity value.

3.4.1 Case 1

Heterogeneity of sand layers varied from the Base Case are stated in Table 6 below. These heterogeneities reduce with increasing depth to assuming to reflect a multi layer reservoir with unconsolidated formation as shallower depths, but gains consolidation with increase in depth.

Table 6: Heterogeneity Variation

Layer	Base Case Permeability (mD)	Case 1 Permeability (mD)
1	1000	4000
2	1000	3000
3	1000	2000
4	1000	1000
5	1000	500

3.4.2 Case 2

Viscosity of oil was reduced to that of Type B oil, which is 10 cP at 75°F in the reservoir. Data regarding this oil type can be seen from Figure 10 from the previous section.

3.4.3 Case 3

Variation in thickness of sand layers from Base Case is shown below.

Table 7: Case 3 sand layer thickness

Sand Layer	Base Case Thickness (ft)	Case 3 Thickness (ft)
1	10	5
2	10	10
3	10	15
4	10	5
5	10	15

3.4.4 Case 4

Frequency and thickness of shale layers are investigated in Case 4. Changes made to base case are shown in Table 8.

Table 8: Shale layer thickness in Case 4

Shale Layer	Base Case Thickness (ft)	Case 4 Thickness (ft)
1	10	5
2	10	10
3	10	15
4	10	5
5	10	15

3.4.5 Case 5

Porosity values investigated in this case are represented in the table below. Less consolidated formation at shallower depth was assumed to have a higher porosity than consolidated formation at deeper depth.

Table 9: Porosity values for Case 5

Sand Layer	Base Case Porosity (%)	Case 5 Porosity (%)
1	30	30
2	30	27
3	30	24
4	30	21
5	30	18

3.5 INJECTION STRATEGY

Different methods of improving recovery from Base Case will be investigated.

3.5.1 Viscosity reduction

Different scenarios of steam quality (SQ) and steam temperature will be investigated to reduce viscosity of oil. Air injection with composition of 60% O_2 and 40% CO_2 was injected with steam will also be experimented numerically as showin in Table 10.

Table 10: Two scenarios for a combination of SQ and steam temperature

Case	Steam Quality	Steam Temperature °F
Base Case	0.7	350
Scenario 1	0.5	350
Scenario 2	0.7	250
Scenario 3	0.5	250
Scenario 4	CO_2 injection with steam	

3.5.2 Mobility ratio

Investigation of viscosity and mobility of steam injected are tabulated below.

Table 11: Viscosity variation in different scenarios at 125°F

Case	Variation from BC	Viscosity (cP)	Mobility
Base Case	-	0.0076	17734
Scenario 5	A_g = $10A_g$	0.052	2583
Scenario 6	A_g = $100A_g$	0.50	271
Scenario 7	$5\mu_{BC}$	0.023	5911

3.5.3 Injection Rate

Two scenarios for injection rates investigated are stated below.

Table 12: Injection Rates

Case	Injection Rate (stb/day)
Base Case	300
Scenario 8	150
Scenario 9	450

3.5.4 Combined Strategy

From results obtained in nine scenarios above, a combination of strategies will be tested.

3.6 INTERPRETATION OF RESULTS

Results obtained will be investigated in terms of

a. Recovery factor,

   This ratio will be calculated by dividing Field Oil Production Total with initial oil in place from .PRT files.

b. Saturation of water,

   Saturation of water with respect to depth of the formation over different time periods can be analyzed in "Schlumberger ECLIPSE Office" by importing "Solution" files.

c. Water cut, and

   This will again be obtained from importing data to "Schlumberger ECLIPSE Office" after simulation runs.

d. Thermal energy of the reservoir.

   Importing files to "Schlumberger ECLIPSE FloViz" allows observation of thermal energy changes in reservoir with respect to spatial difference.

Comparison between water and steam injection will be carried out in the first section. Improvement of injection strategies will be investigated in the second section.

3.7 WORKFLOW SUMMARY

The following chart shows stages involved leading to project completion.

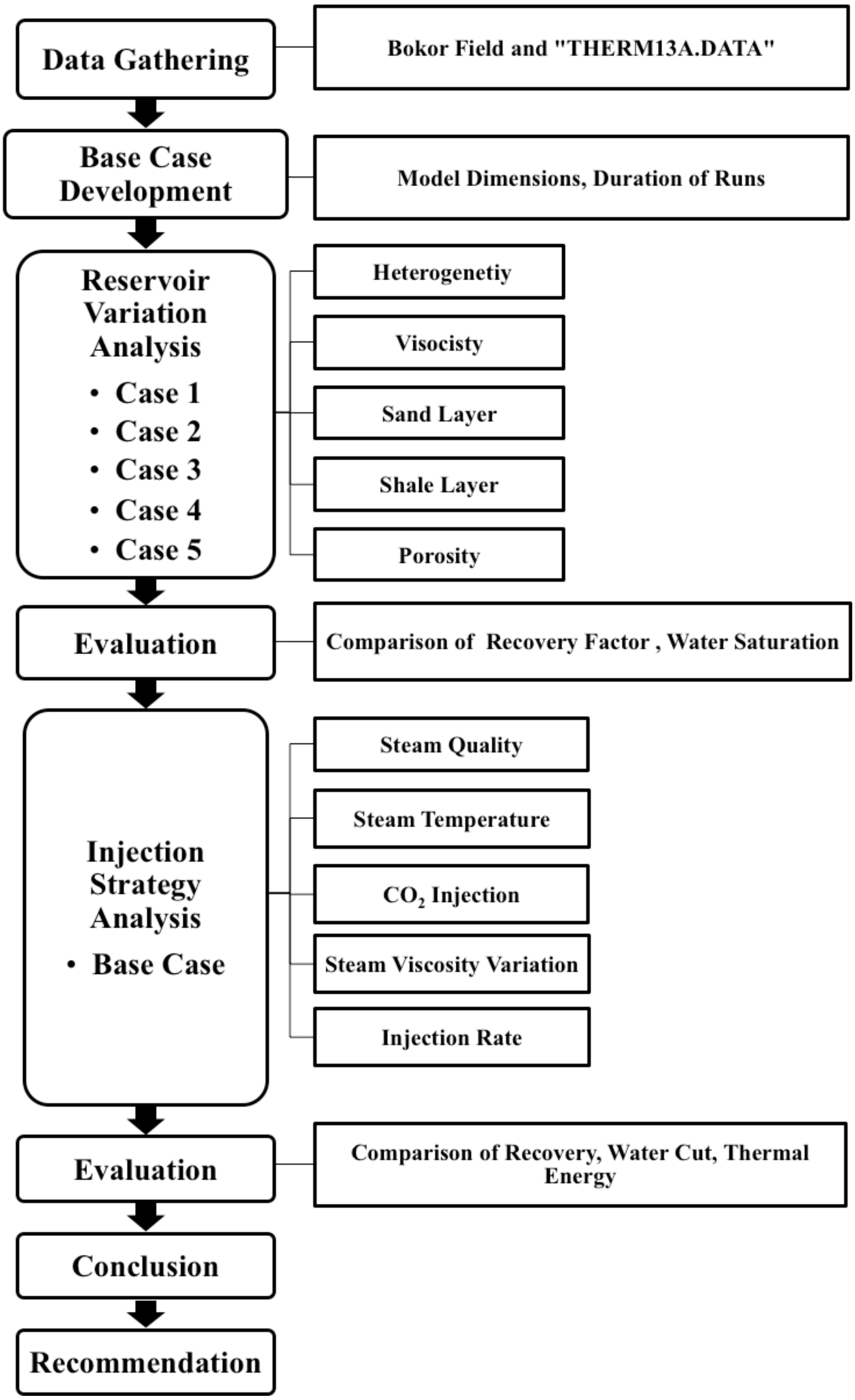

Figure 13: Workflow of project

CHAPTER 4

RESULTS AND DISCUSSION

4.1 ANALYSIS OF RESERVOIR PROPERTIES

Results from variation of four geological and one fluid parameter from Base Case are presented in the following sections.

4.1.1 Water Flooding

Recovery factor results after duration of 5 years from water flooding is tabulated below.

Table 13: Recovery for all water flooding cases

Water Flooding		
Case	Recovery Factor (%)	Difference from BC (%)
Base Case	68.5	-
Case 1	67.9	-0.9
Case 2	69.7	1.9
Case 3	68.5	0.0
Case 4	68.5	0.0
Case 5	69.2	1.0

Among five cases investigated when carrying out water flooding, Case 2 resulted with the highest recovery. As expected, recovery from less viscous oil is more than that of viscous oil. However, although viscosity of oil was reduced by 85.1% from its value of 67.3 cP to 10 cP, recovery was only increased by 1.9% with waterflood.

With a formation of reducing sand heterogeneity, recovery was reduced by 0.88% compared to the Base Case. Sand layer at Unit 5 with the lowest permeability (500 mD) still contained saturation of oil up to around 29.0% as observed from Figure 14.

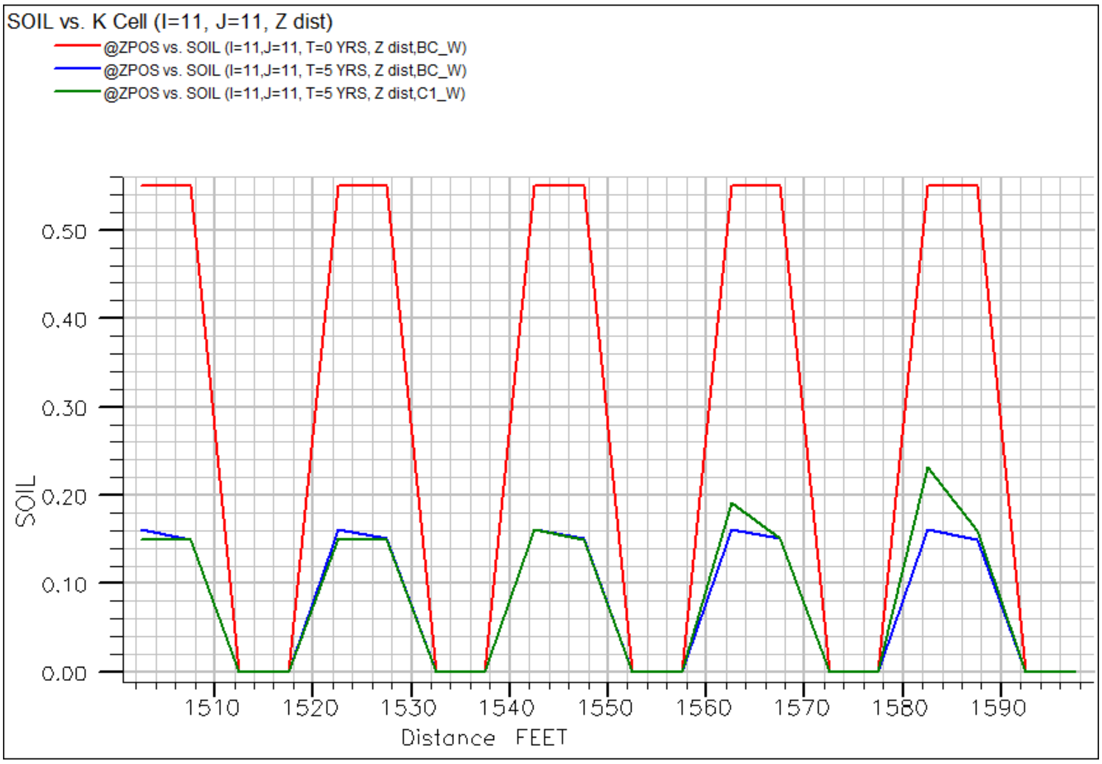

Figure 14: Saturation with depth at cell X=18, Y=18, Z

Recovery remains unaffected by changes in thickness and frequency variation of sand and shale layers. Reducing porosity values with increase in depth lead to 1% more recovery. Higher porosity contains a larger volume of Stock Tank Oil Initially in Place, relative to a formation with lower porosity. However, when injection rate is the same in both cases, amount of STOIIP recovered is approximately the same. This results in formation with lower porosity to have a higher recovery factor.

Overall behavior of recovery for five years is shown in Figure 15.

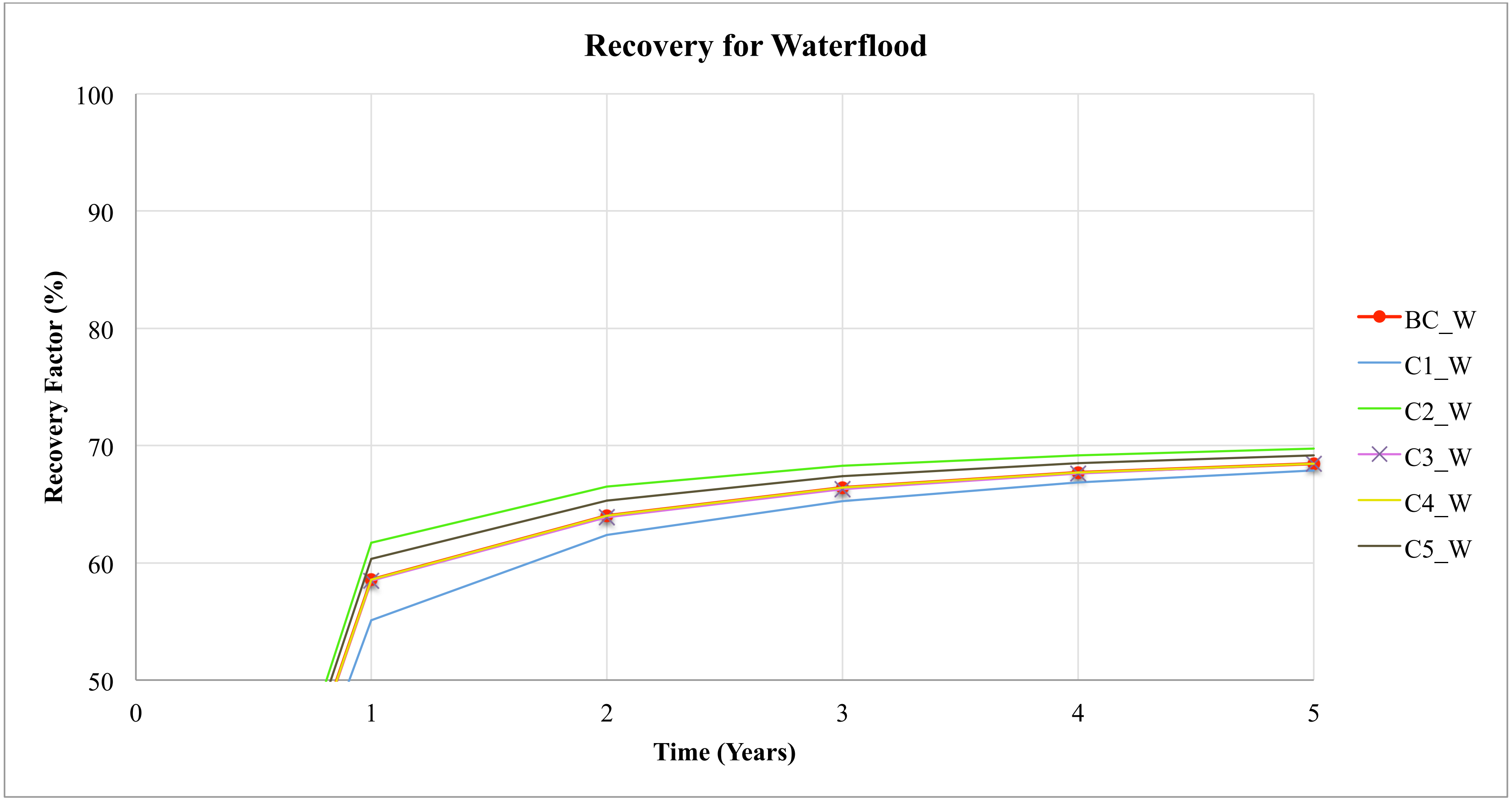

Figure 15: Recovery for Waterflood

4.1.2 Steam Flooding

Steam flooding with steam quality (SQ) of 0.7 and temperature of 350°F was carried out for all cases and the results are presented below. Production with respect to time is shown in Figure 16.

Table 14: Recovery for all steam injection cases

Steam Flooding		
Case	Recovery Factor (%)	Difference from BC (%)
Base Case	83.9	-
Case 1	66.6	-20.5
Case 2	90.9	8.3
Case 3	84.6	0.8
Case 4	81.8	-2.5
Case 5	85.2	1.6

Recovery was affected the most by heterogeneity variation as production reduced by 20.5%. Early steam breakthrough in high permeability layers at shallower sand reduces efficiency of steam injection. Vertical conformance was observed.

Production for Case 4 was also reduced by 2.5%. Due to heat losses in the well bore and into the formation, efficiency of steam decreases with an increase in depth. Shale layers further away from heat source will be less efficient in reducing viscosity of heavy oil.

Case 2, 3 and Case 5 were analyzed to have an increased in production of 8.3%, 0.8% and 1.6% respectively. Increase in production of Case 2 concurred with predicted result. For Case 3, existence of thicker sand layers (15 ft) contributed to the slight increase in recovery factor as it is easier to produce from thick layer.

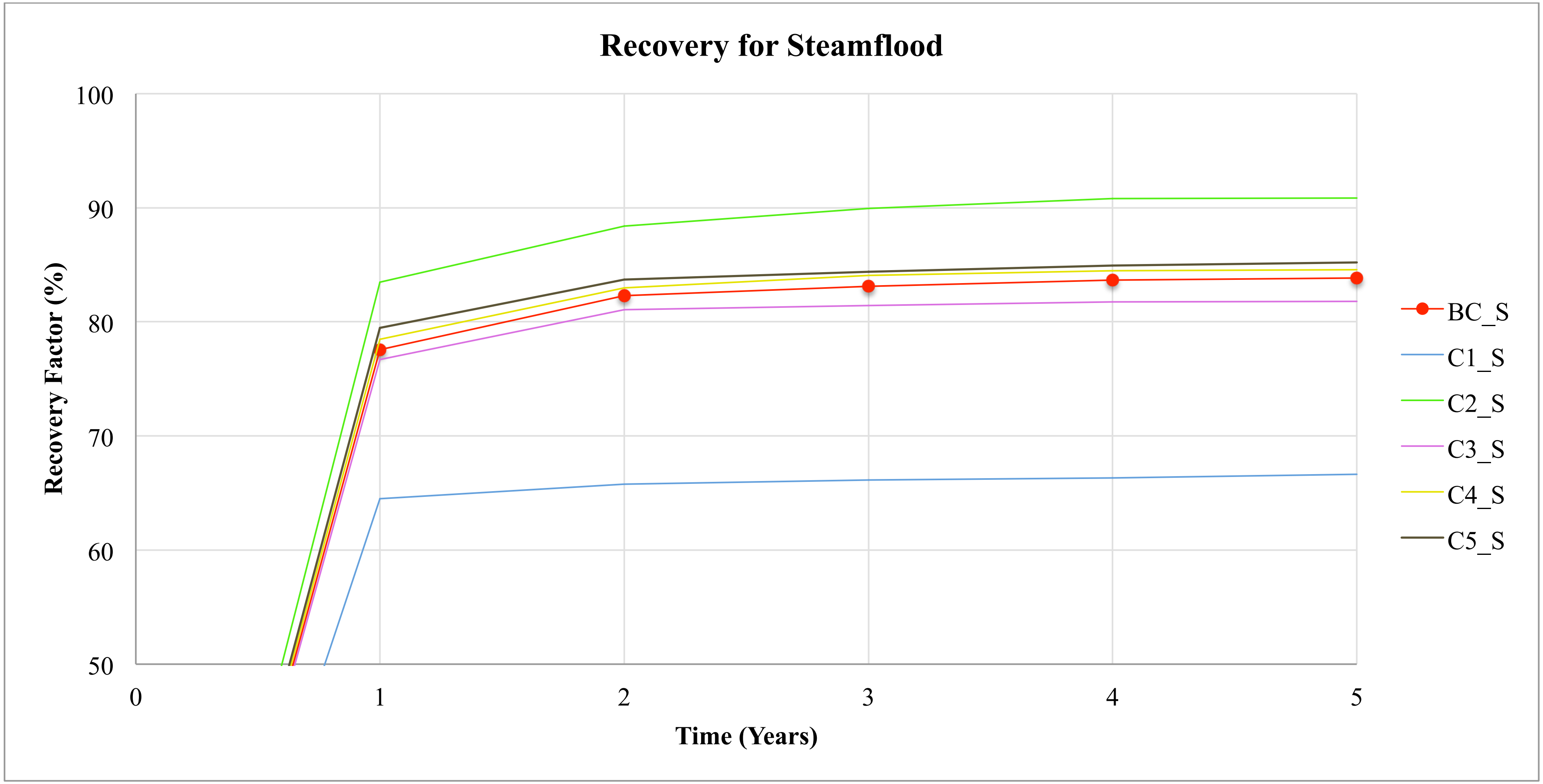

Figure 16: Recovery for Steamflood

4.1.3 Sensitivity Analysis on Geological Parameters

Steam injection has a larger impact when compared to water injection. Cases 1 and 4 showed increase in production for both recovery methods. Water flooding has a positive effect on Case 3, but otherwise for steam flooding. Increase in porosity decreased recovery for both cases.

Sensitivity of water injection Figure 17**:** 10% reduction in all four geological parameters only resulted in recovery of porosity to increase. With the same injection pressure for all pore sizes, approximately the same volume is being displaced from the pores. However, more hydrocarbon is initially in place for porosity of higher value. Therefore, in terms of recovery, the smaller pores will then have a higher recovery factor. Increasing all these parameter values by 10% gained the most recovery with heterogeneity change. Changes in sand and shale frequency, and thickness did not affect recovery as much. For all cases, a 10% change in all the factors resulted in less than 1% difference in recovery.

Sensitivity of steam injection Figure 18**:** Relative to water flooding, 10% change in all parameters varied RF more from Base Case, with changes in porosity as the most sensitive parameter. Water saturation is higher in pores with lower porosity. A possible reason for increase in recovery for Case 5 is from expansion of water, which provides an extra drive. For Case 3, increase in sand layer thickness resulted in a lower recovery. As injection rate is fixed at 300 stb/day for both cases, the case with lower volume of STOIIP will have more thermal energy per unit volume. However, viscosity is reduced more. Increase in shale layer thickness increases recovery. As injection rate is fixed, for a formation with thicker shale layer, pressure entering each permeable layer is lower. This would create a more stable front and allow more time for efficient heat transfer to viscous oil. Pressure difference can be observed in Figure 19. 10% change in the geological parameters also exhibited less than 1% change in recovery for all the factors.

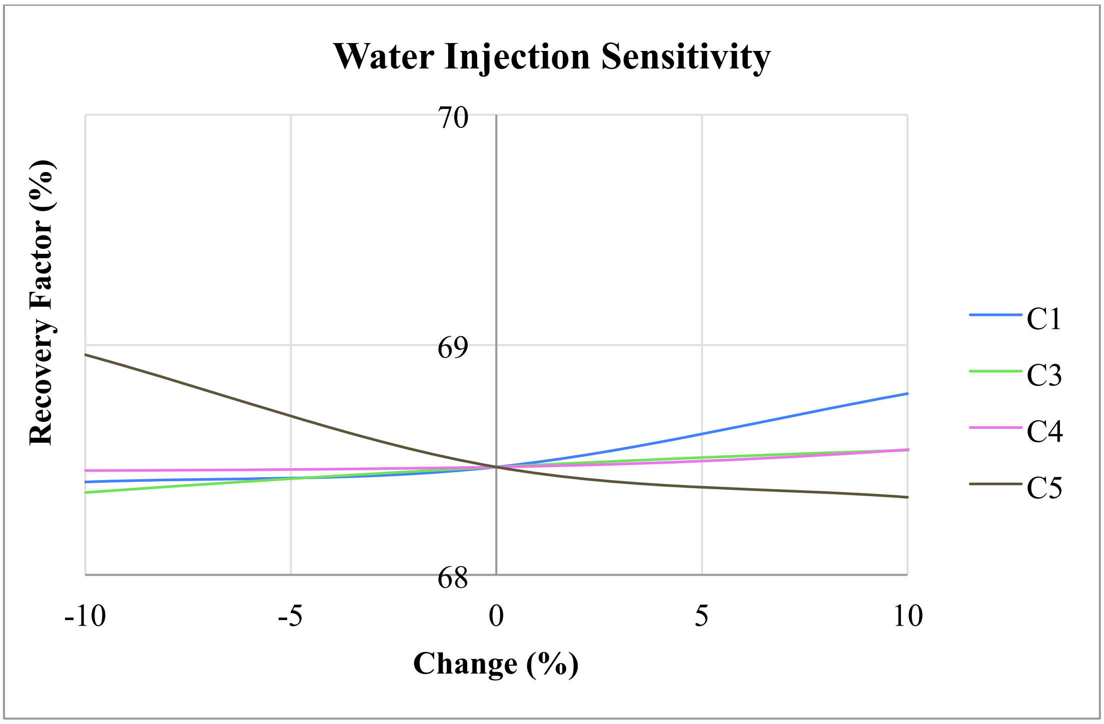

Figure 17: Sensitivity for Waterflood

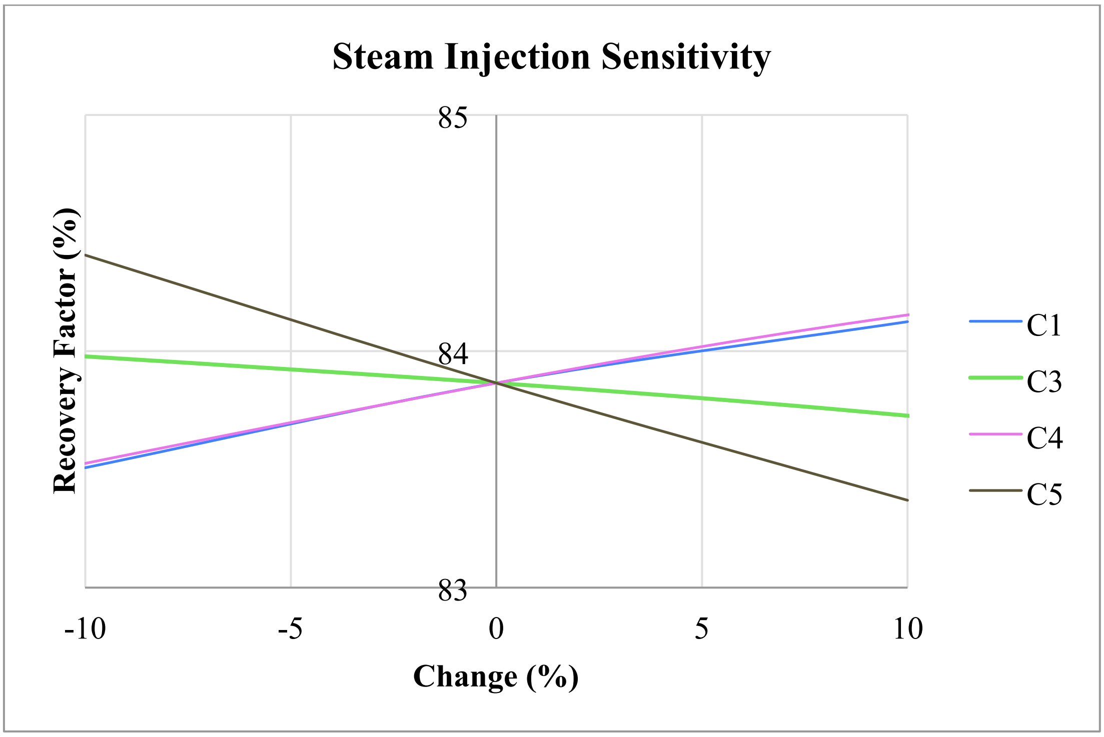

Figure 18: Sensitivity for Steamflood

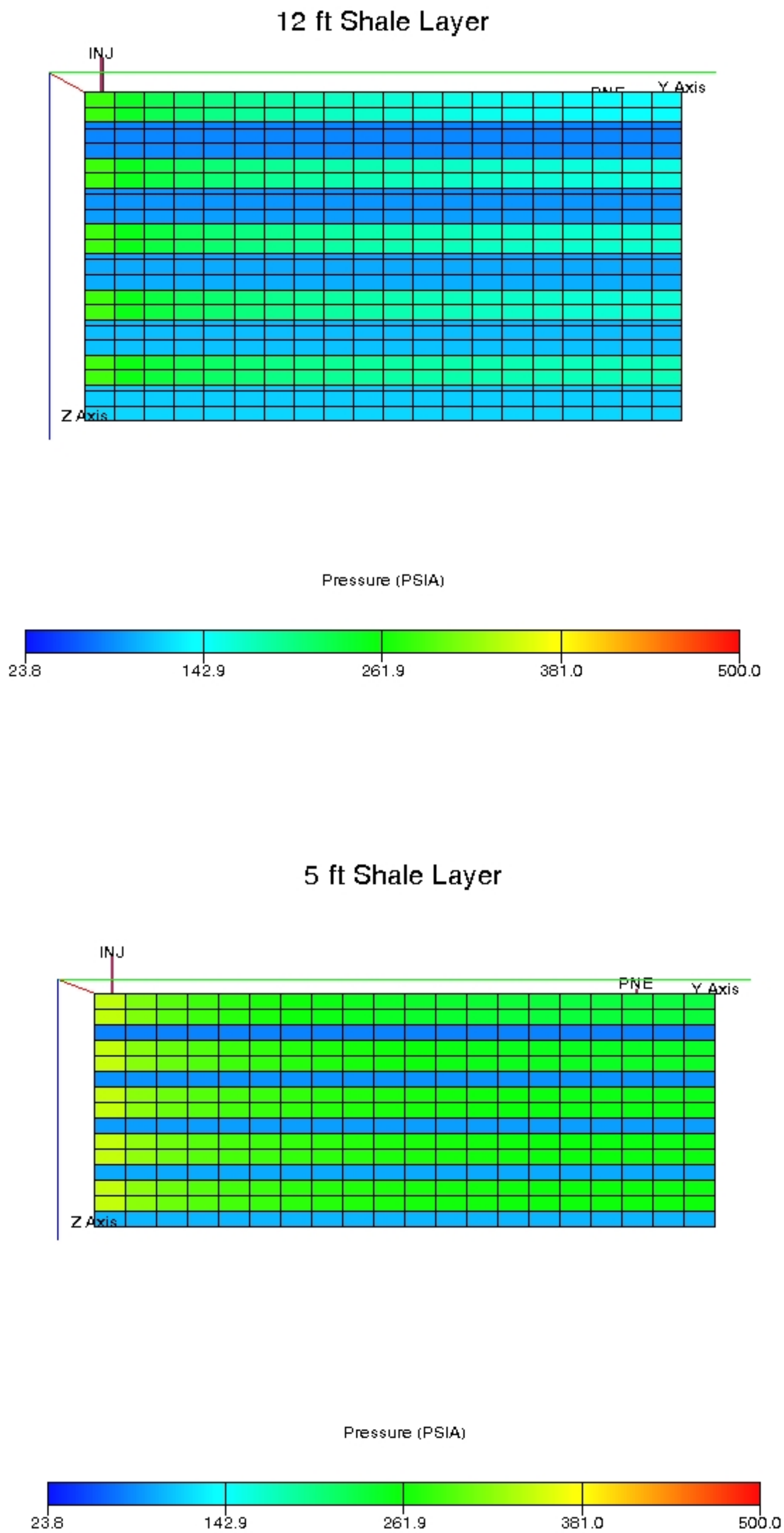

Figure 19: Pressure distribution after one year for 12 ft and 5 ft shale layers

4.2 BASE CASE RECOVERY IMPROVEMENT

4.2.1 Recovery Factor

Among all the methods to improve recovery in this project, Scenario 6 and 11 proved to be most effective, yielding a recovery factor of 7.4% more than Base Case. Scenarios 10, 11 and 12 investigated a combination of different injection strategies.

Table 15: Results from twelve injection strategies

Scenario	Alterations from BC	RF (%)	Difference from BC (%)
BC	Steam Injection	83.9	-
1	SQ 0.5, Temp 350°F	83.9	0
2	SQ 0.7, Temp 250°F	83.9	0
3	SQ 0.5, Temp 250°F	83.9	0
4	CO_2 Injection	80.7	-3.2
5	$A_g = 10A_{g_{BC}}$	88.4	5.2
6	$A_g = 100A_{g_{BC}}$	91.2	7.4
7	$5\mu_{BC}$	88.8	5.0
8	Injection Rate 150 stb/day	85.7	1.8
9	Injection Rate 450 stb/day	81.9	-2.0
10	$5\mu_{BC}$, IR 150 stb/day	88.8	4.9
11	$A_g = 100A_{g_{BC}}$, 150 stb/day	91.3	7.4
12	$A_g = 100A_{g_{BC}}$, 100 stb/day	90.9	7

Scenarios 1 to 3 investigated different steam quality and steam temperature. Recovery factor did not increase in all three cases. Instead, varying steam quality and temperature resulted in different production rates. Scenario 2 had highest production in the earlier stage relative to Scenario 1 and 3. Scenarios with higher steam quality accelerated production in the first two years. Steam injected at 350°F showed a small variation relative to that of 250°F as shown in Figure 20.

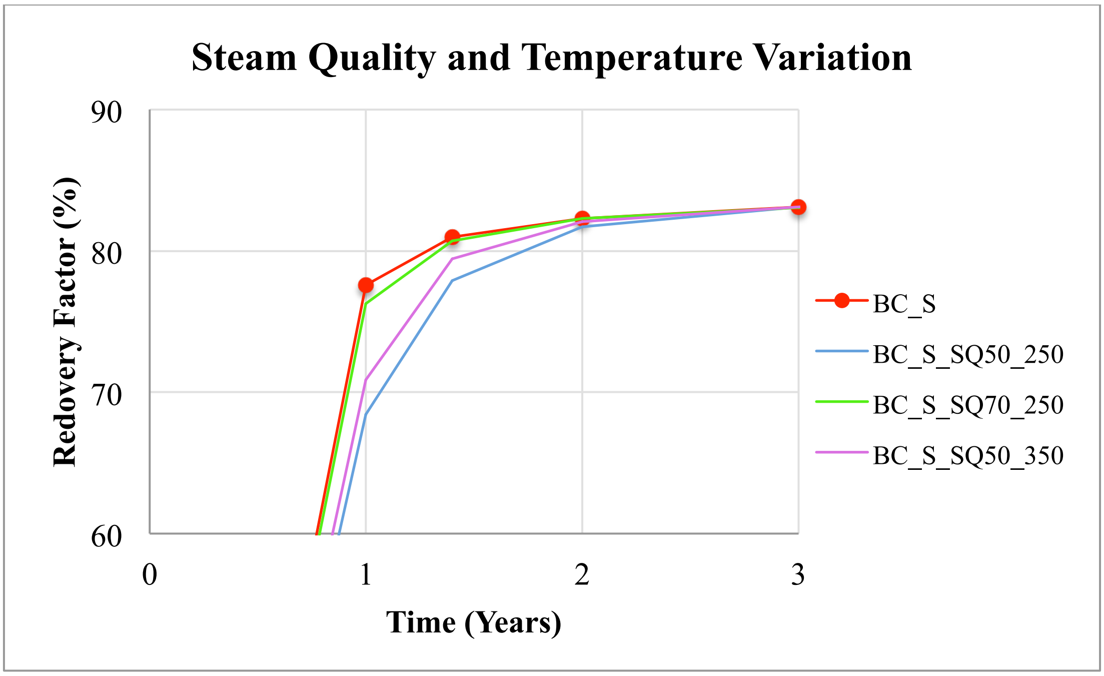

Figure 20: Steam Quality and Temperature effect

Reduction in production from CO_2 needs further investigation. Minimum Miscible Pressure (MMP) required for CO_2 miscible displacement is high with higher temperature could be an explanation for this. Temperature affects MMP the most in a study carried out by Yellig and Metcalfe. CO_2 MMP pressure increased by approximately 15 psi/°F, over a temperature range of 95 to 192 °F [**38**]. Reservoir has to be able to withstand high pressure. Thermal energy of steam would also be transferred to CO_2 gas (assumed to be injected at surface temperature), hence reducing efficiency of heating up viscous oil.

Increasing injection rate to 450 stb/day also did not favor production. Steam breakthrough is faster. Time is also needed to conduct heat high viscous oil efficiently. Increasing viscosity of steam lowered mobility ratio, and improved recovery by 5 to 7%. However, water cut in these scenarios escalated to almost 100%.

4.2.2 Water cut

Water cut for steam injection was high even at year two for Base Case steam injection. This unfavorable condition was investigated further, and with lower injection rate and higher viscosity. Water production was delayed and reduced to 96%. Production was increased by 7% from the base case, as observed in Scenario 12. Values for water cut at the end of five years are tabulated in Table 16. Behavior of water cut with top three highest production scenarios are shown in Figure 21.

Table 16: Field Water Cut Total at the end of five years

Scenarios	Water Cut (%)	Difference from BC (%)
BC_S	99	-
6	99	0
11	99	0
12	96	3

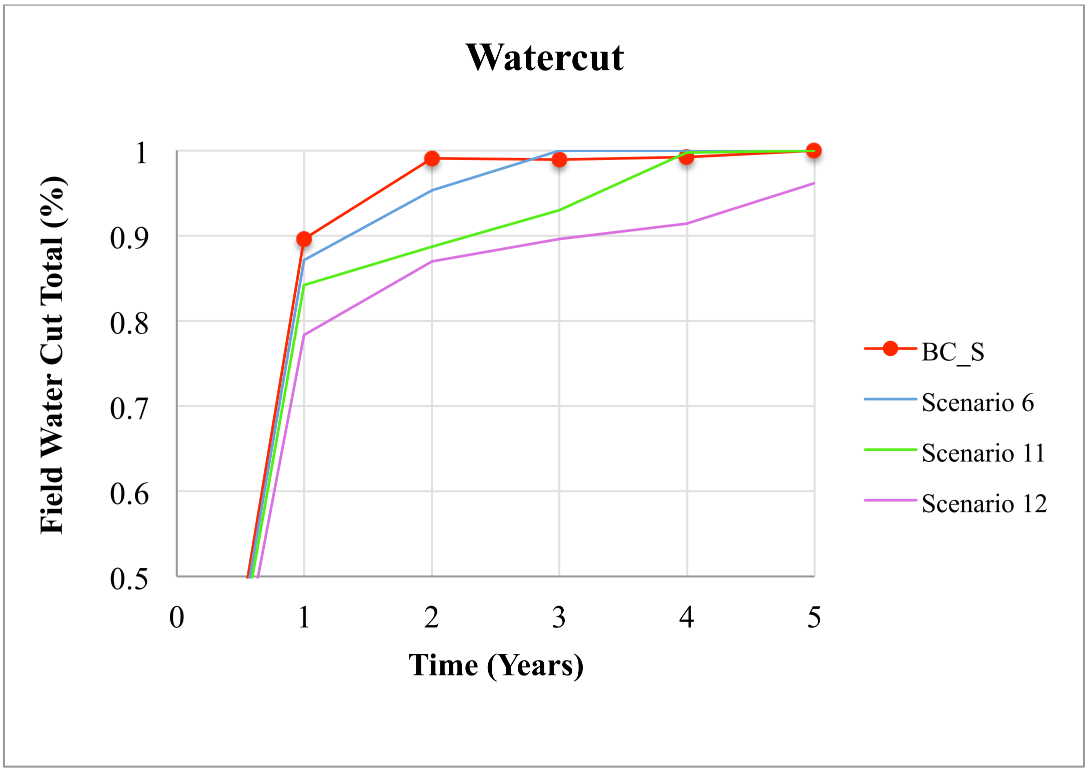

Figure 21: Water cut for selected scenarios

4.3 THERMAL EFFECT

In sand layers, heat is conducted away from the source more rapidly relative to shale layers. Conduction and convection are the two major heat transfer mechanisms in sand layers. As for shale layers, conduction is the only dominant mechanism. This resulted in higher temperature in sand rather than shale layers after 100 days. As expected, temperature of shale layers at grid with same x- and y-coordinate at a deeper depth is at a lower temperature when compared with the grid at a shallower depth, due to heat loss.

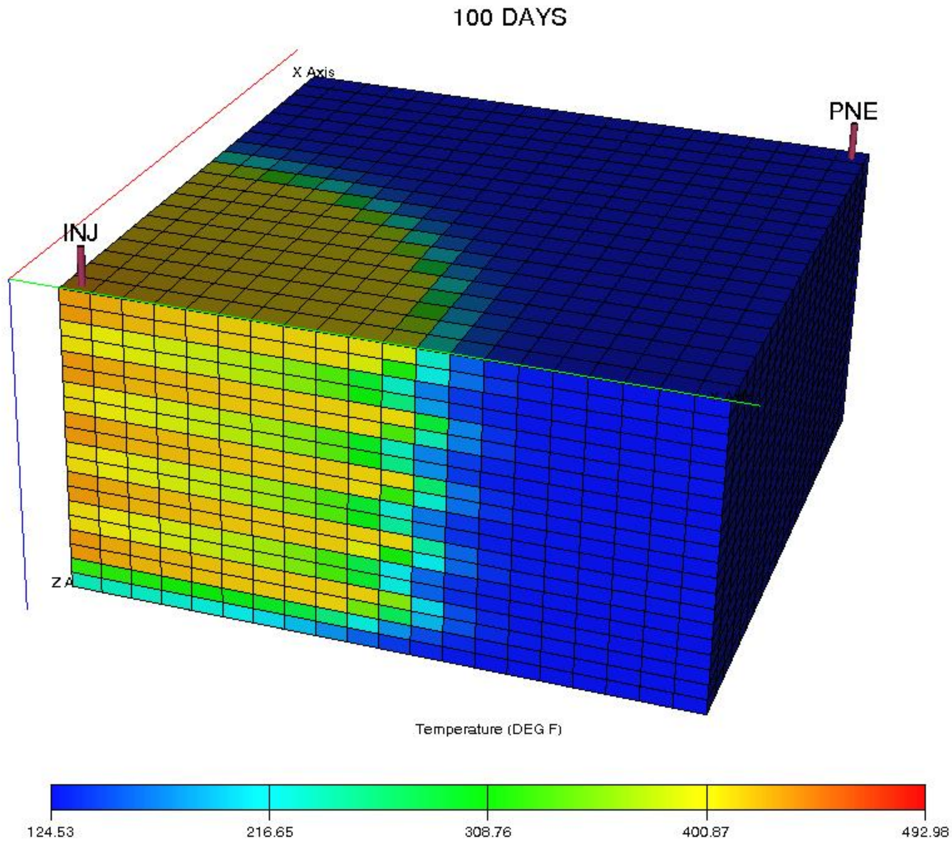

Figure 22: Steam injection after 100 days of injection for BC_S

When Field Heat Loss Total (FHLT) was analyzed, the following was data in Table 17 was obtained. Behavior of Field Heat Loss Total (FHLT) from year one to five can be seen in Figure 23.

Table 17: Field Heat Loss Total at the end of five years

Scenarios	FHLT x 10^{10} (BTU)	Reduction from BC (%)
BC_S	2.76	-
6	2.69	2.6
11	2.17	21.5
12	1.53	44.5

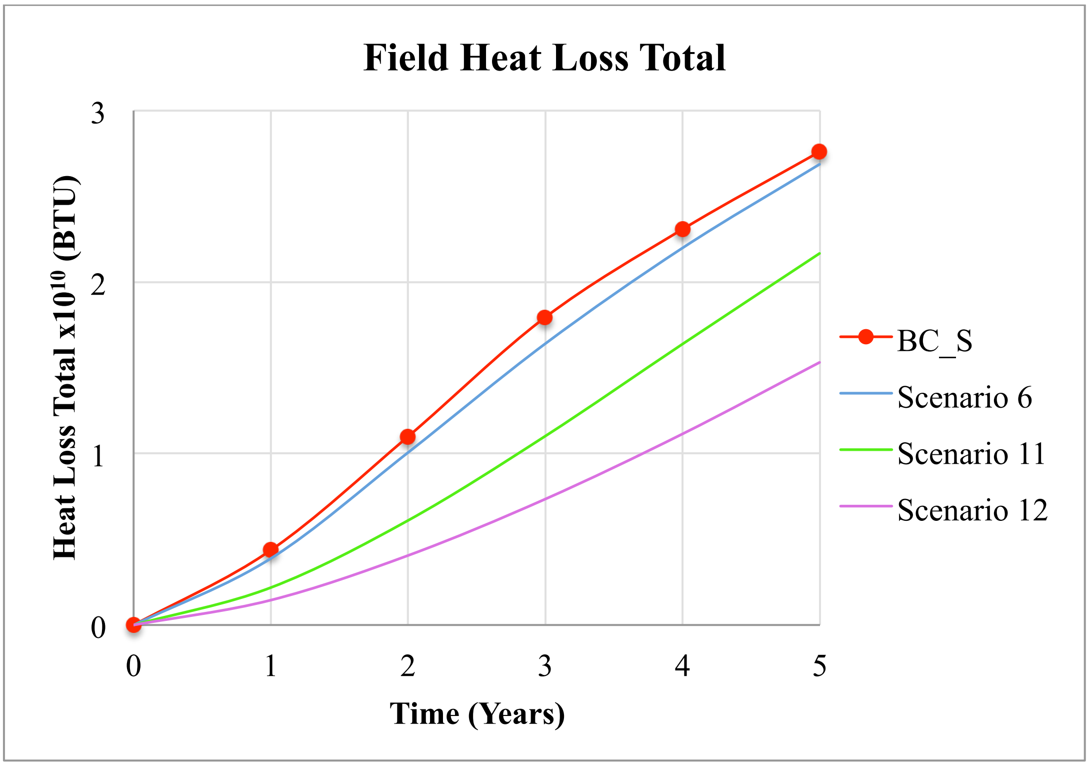

Figure 23: Field Heat Loss behavior

From Figure 24, temperature difference of the reservoir after five years in Base Case steam injection and Scenario 12 can be observed. Temperature is more evenly distributed over all five units in Scenario 12.

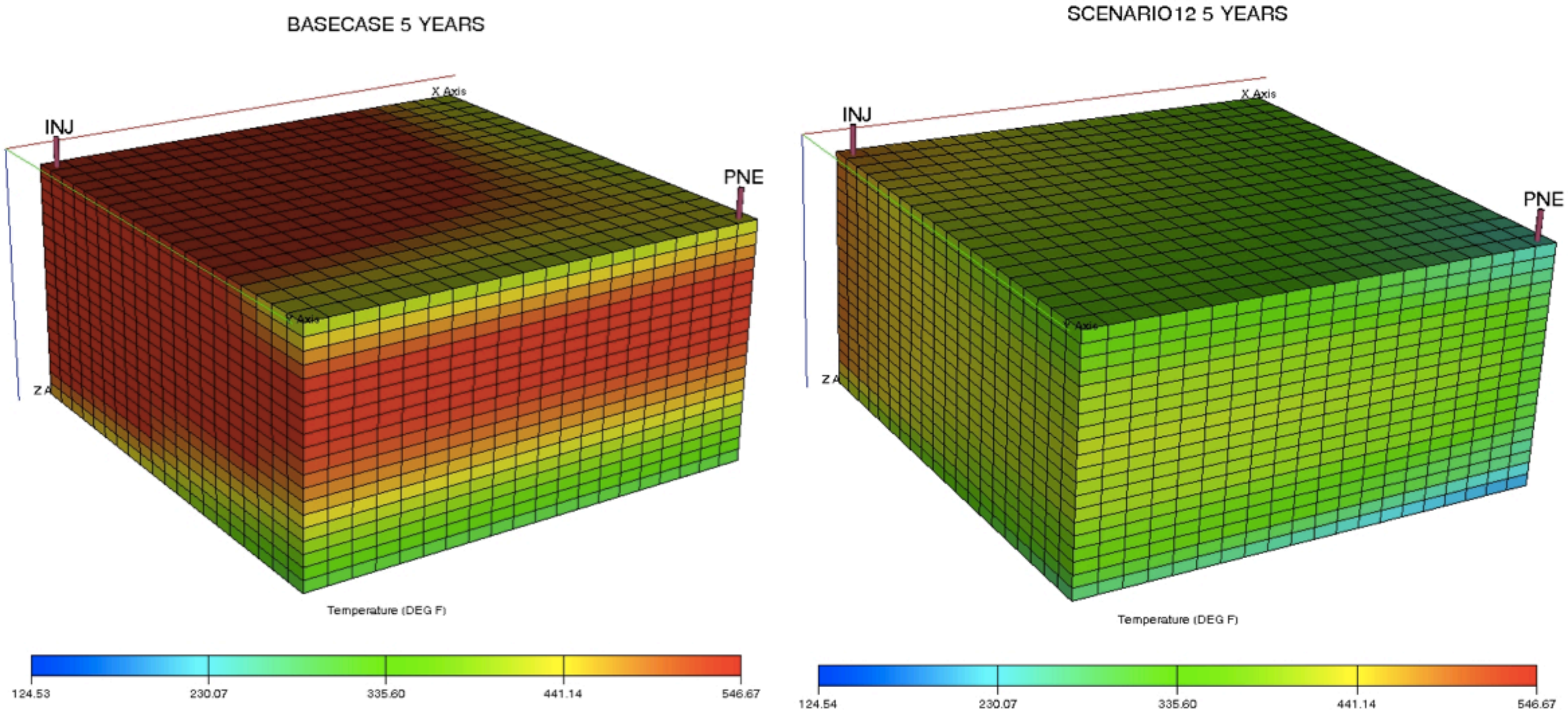

Figure 24: Temperature comparison of Base Case model and Scenario 12 after 5 years

CHAPTER 5

CONCLUSIONS AND RECOMMENDATION

5.1 CONCLUSIONS

Conclusions for this project are stated as below:

a. 3-D compositional model was used to carry out basic parameter and strategy variations,
b. Geological parameters are more sensitive when carrying out steam injection,
c. Reduction in porosity by 10% increases recovery factor for both water and steam flooding by 0.5% in both cases,
d. For waterflood, out of five parameters investigated, changes in heterogeneity between layers, oil viscosity and porosity values contribute to a change in recovery,
e. For steamflooding, all factors are affected with heterogeneity and changes in oil viscosity parameters being significantly more sensitive than the others,
f. In both water and steam flooding, 10% changes in all four geological parameters resulted in less than 1% change in recovery,
g. Variation of steam temperature of 250°F and 350°F and steam quality of 0.7 and 0.5 did not improve recovery at the end of five years,
h. At the same temperature, higher steam quality accelerates production,
i. Decreasing mobility ratio by 98% improved recovery by 5% to 7%,
j. Lowering injection rate by 50% improved recovery by 1.8%, and
k. Lowering of injection rate by 66% and mobility ratio by 98% reduced water cut by 4%, improved recovery by 7% and reduced thermal heat loss by 44.5%. Polymer with such ability has yet to be identified.

5.2 RECOMMENDATIONS

The project can be investigated further by considering the following

a. Permeability Reduction

   For Case 1, investigation in reduction of high permeability layered zone through mechanical or chemical methods can be carried out.

b. Dip of the reservoir,

   Inclination of the reservoir between 0° to 15° should be considered.

c. Grid refinement,

   Instead of having two layers of grid to represent a 10 ft thick sand layer, five layers of grid can be used.

d. Lean gas injection,

   This injection method could be analyzed to see its feasibility with current reservoir condition.

e. The use of surfactants to reduce IFT,

   This could lead to an increment in recovery. Reactions governing reduction in IFT should be analyzed.

f. Microbial EOR,

   This requires detailed understanding of reactions and behavior of microbial.

g. History matching with existing data.

   Real field data should be used to ensure investigation is more realistic, and degree of numerical dispersion error can be identified.

h. Heat losses

   Investigation on other different strategies could be carried out to increase thermal efficiency

Alternative methods to improve steam flooding can perhaps be done through extensive research of chemicals, which have both high viscosity and latent heat. Steam with viscosity of 0.5 cP could be formed by mixing steam with polymer.

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APPENDICES

Appendix A

Thermal Keywords

Table 18: Thermal keywords used in coding

<table>
<tr><td colspan="2">Section</td><td>Keyword</td><td>Description</td></tr>
<tr><td colspan="2">RUNSPEC</td><td>THERMAL</td><td>Selects thermal option and live oil model is activated by default</td></tr>
<tr><td colspan="2" rowspan="2">GRID</td><td>HEATCR</td><td>Rock volumetric heat capacity</td></tr>
<tr><td>THCONR</td><td>Thermal conductivity of rock and fluid</td></tr>
<tr><td rowspan="6">PROPS</td><td rowspan="5">Hydrocarbon Properties</td><td>GASVISCT</td><td>Table of gas viscosity with respect to temperature</td></tr>
<tr><td>OILVISCT</td><td>Table of oil viscosity with respect to temperature</td></tr>
<tr><td>KVCR</td><td>Defining K-Values</td></tr>
<tr><td>TCRIT</td><td>Defining critical temperature for accurate surface calculations</td></tr>
<tr><td>ZFACTOR</td><td>Z-factor zeroth coefficient</td></tr>
<tr><td>Water properties</td><td>THANALB</td><td>Analytic water and steam densities</td></tr>
</table>

Appendix B

Base Case code

```
RUNSPEC   ==========================================

NOSIM

FIELD

DIMENS
 20 20 20 /

WATER
OIL
GAS

COMPS
 5    /

THERMAL

AIM

ROCKDIMS
 2 /


GRID      ==============================================

INIT

TOPS
 400*1500.0  /

DXV
 20*10.0 /

DYV
 20*10.0 /

DZV
 20*5 /

PERMX
 800*1000.0  800*0
 800*1000.0  800*0
 800*1000.0  800*0
 800*1000.0  800*0
 800*1000.0  800*0/
```

```
COPY
 PERMX PERMY/
 PERMX PERMZ/
/

PORO
 800*0.3  800*0
 800*0.3  800*0
 800*0.3  800*0
 800*0.3  800*0
 800*0.3  800*0/

THCONR
 8000*24.0
/

HEATCR
 8000*35.0
/


ROCKPROP
 1  125  24  35 0 N  /  overburden
 2  125  24  35 0 N  /  underburden
/

ROCKCON
 1  1  20  1  20  1   1    'K-'      /  top
 2  1  20  1  20  20  20  'K+'      /  bottom
/


PROPS     ========================================

CNAMES
 C1 C2 HEAVY O2 CO2/

KVCR
--   C1     C2    HEAVY    02   CO2
  1.23E6  212          1*      0     0
  833.4E6 155.4E3  1*      0     0
  0            0            1*      0     0
  16000    4000        1*      0     0
  0            480          1*      0     0
/


CVTYPE
 LIVE LIVE DEAD GAS GAS  /
```

```
TCRIT
 1259.67  1409.67  10000   1*    1*/

PCRIT
 225.         140.      100.0   730   750/

MW
 250           450       600     32      44/

CREF
 .00005    .00005   .00005    1*    1*/

DREF
 52.3          57.64    61.2       1*    1*/

THERMEX1
 .00036     .00037   .00038    1*    1*/

ZFACTOR
 0.96          0.97     0.99       1.87  1.87/

THANALB

SPECHA
 .53           .55         0.6       0.4    0.4/

HEATVAP
 230.0      100.0 /

TEMPVD
--Depth  Temperature
  1300.0    125.0
  1700.0    125.0  /

STCOND
--Temp   Pressure
  60     14.7 / 3 /
```

```
SWFN
-- SWAT     KRW    PCW
   .4500   .0000   0.0
   .4900   .0003   0.0
   .5300   .0018   0.0
   .5700   .0049   0.0
   .6100   .0101   0.0
   .6500   .0177   0.0
   .6900   .0279   0.0
   .7300   .0410   0.0
   .7700   .0572   0.0
   .8100   .0768   0.0
   .8500   .1000   0.0
  1.0000   .1000   0.0
 /

SGFN
-- SGAS     KRG    PCG
   .0000   .0000   0.0
   .0600   .0000   0.0
   .1090   .0063   0.0
   .1580   .0179   0.0
   .2070   .0329   0.0
   .2560   .0506   0.0
   .3050   .0707   0.0
   .3540   .0930   0.0
   .4030   .1171   0.0
   .4520   .1431   0.0
   .5010   .1708   0.0
   .5500   .2000   0.0
  1.0000   .2000   0.0
 /

SOF3
-- SOIL     KROW    KROG
   .0000   .0000   .0000
   .1000   .0000   .0000
   .1500   .0000   .0049
   .1900   .0040   .0160
   .2300   .0160   .0334
   .2700   .0360   .0571
   .3100   .0640   .0871
   .3500   .1000   .1235
   .3900   .1440   .1661
   .4300   .1960   .2151
   .4700   .2560   .2704
   .5100   .3240   .3320
   .5500   .4000   .4000
  1.0000   .4000   .4000
 /
```

```
GASVISCT
-- Temp  Viscosities
   75   0.0143    0.0285  1.0   0.0014  0.0014
  100   0.0149    0.0297  1.0   0.0015  0.0015
  150   0.0161    0.0321  1.0   0.0016  0.0016
  200   0.0172    0.0345  1.0   0.0017  0.0017
  250   0.0184    0.0368  1.0   0.0018  0.0018
  300   0.0196    0.0391  1.0   0.0020  0.0020
  350   0.0207    0.0414  1.0   0.0021  0.0021
  500   0.0241    0.0483  1.0   0.0024  0.0024
15000   0.2946    0.5892  1.0   0.0030  0.0030
/

OILVISCT
-- Temp  Viscosities
   75    2.3 10.6  67.3      1.3    1.3
  100    2.0  9.1  31.5      1.0    1.0
  150    1.5  6.8  12.8      0.5    0.5
  200    1.1  5.2   7.5      0.1    0.1
  250    0.9  4.1   6.4      0.09   0.09
  300    0.7  3.2   5.2      0.07   0.07
  350    0.6  2.6   4.8      0.06   0.06
  500    0.3  1.4   2.3      0.03   0.03

/

PVTW
--  Pref      Bw       Cw         Vw       Cvw
--  PSIA      RB/STB    1/PSI      CPOISE    1/PSI
    75.000     1.0       3.E-06     .3       7.E-09
 /

ROCK
 75.0  5.0E-04  /

ZMFVD
 1500.0    0.5030    0.1614   0.3356    0.0000   0.0000 /

THSVC
 4.9402E-3 5.0956E-5 2.9223E-6 2.5077 /

SOLUTION  =========================================

EQUIL
--  Ddat    Pdat    Dwoc    Pcog    Dgoc    Pgoc  It1  It2  Iac Iin
 1505.0     75.0     1600.0  0.0     1500.0  0.0   1     1    0   1  /

RPTRST
 PRES TEMP ENERGY SOIL SWAT SGAS MLSC AIM RATP RATS RATT /
```

```
RPTSOL
 PRES TEMP ENERGY SOIL SWAT SGAS MLSC /

SUMMARY   ===========================================

ALL

FPR

WSTPR
 PNE /

WSTPT
 PNE /

FOSRC

FHLR

FHLT

-- Performance data

PERFORMANCE

-- Run summary file

RUNSUM

RPTONLY
SCHEDULE  ===========================================

RPTPRINT
-- s F R G S W C s nl
   1 1 0 0 0 1 0 1 0 /

RPTSCHED
 PRES TEMP ENERGY SOIL SWAT SGAS MLSC AIM /

WELLSTRE
 AIR 0 0 0 0.6 0.4 /
/

WELSPECS
INJ   FIELD  1  1  1* WATER /
PNE   FIELD  20 20 1* OIL   /
/
```

```
COMPDAT
INJ  1  1  1  2     OPEN 1   1* /
INJ  1  1  5  6     OPEN 1   1* /
INJ  1  1  9  10   OPEN 1   1* /
INJ  1  1  13 14  OPEN 1   1* /
INJ  1  1  17 18  OPEN 1   1* /


PNE  20 20 1  2     OPEN 1   1* /
PNE  20 20 5  6     OPEN 1   1* /
PNE  20 20 9  10   OPEN 1   1* /
PNE  20 20 13 14  OPEN 1   1* /
PNE  20 20 17 18  OPEN 1   1* /
/


WCONINJE
--Well Type  ...  Init Rate Res BHP
  INJ  WATER OPEN RATE 300 1*  1000.0 /
/
WINJTEMP
--Well SQ   Temp
  INJ  0.7  350   /
/

-- Production targets

WCONPROD
--Well  ...  Init Oil Wat Gas Liq Res BHP ... Steam
PNE     OPEN BHP  3*         1000 1*  17  5*  10.0 /
/

CVCRIT
--MaxDP MaxN RMS MaxL ... MinL MaxS MaxT MinN RMS MMN
  1*    1*   1*  1*   1*  1*   1*   1*   1*   1*  1*
--MSR   Slim Tlim Plim
  1*    5.0  180   1*   /


TSTEP
 1*1 /
 1*364
 4*365 /


END
```