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Journal of Earth Energy Engineering

Publisher: Universitas Islam Riau (UIR) Press

Numerical Simulation Study of Steam Injection Optimization in Shallow Reservoir

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Article History:

Received: May 20, 2023
Receive in Revised Form: May 31, 2023
Accepted: June 10, 2023

Keywords:

shallow reservoir, steam injection, Cumulative Steam-Oil ratio

Abstract

In an EOR project, process improvement must be continually pursued since EOR is often marginally profitable. In steamflood EOR project, steam injection rate is very important parameter to ensure that each pattern reach maturity within a certain early period that result in high oil recovery and meet the economic hurdles. In particularly shallow formation settings, steam injection target is often difficult to achieve because limited by fracturing pressure to avoid breaching the cap rock and creating environmental problem. In this study we simulate steam injection in a typical heavy oil reservoir (high API, shallow depth, low pressure) to enable optimization of steam injection. A model has been built using typical shallow reservoir in using Builder-CMG. Wellan data, fluid model and operating conditions (injection strategy, steam quality) and expected/ forecasted performance. CMOST package is then used to design optimization study by varying the steam injection rate. The best scenario is based on the lowest reservoir pressure and cumulative SOR. We created three development options: regular inverted 7-spot 15.5-acre pattern, horizontal well and pattern size reduction (PSR). From this numerical study it is found that for the case studied, steam injection rate can be ramped up from 250 - 300 BSPD within 6-7 years, followed by peak production. A wind down injection rate to 0 can be used after this peak production to achieve CSOR target of 3-4 bbl of steam/bbl of oil. If a quicker SBT is required, then more steam injectivity is needed to put underground. Several scenarios can be considered as follow: (1) reducing the pattern size (thus adding steam via additional injection wells) and (2) utilizing horizontal wells.

INTRODUCTION

According to resources triangle theory, non-conventional hydrocarbon available in much larger quantity than conventional oil. Heavy oil is among other non-conventional oil whose role become increasingly important amid increasing demand (despite efforts to switch to renewable energy sources) and depleting reserves. This non-conventional nature requires advanced technologies and associated higher cost, however the cost per barrel will typically reduce as the technology matures.

Common EOR technology to exploit heavy oil is by injecting steam to drive remaining oil to the production well or to achieve steam breakthrough and oil be produced through density difference and viscosity reduction mechanisms via gravity drainage. Thermal methods are better option where quick payout is demanded as the energy rate injected is high. This method suitable for viscous, low gravity oil although some projects have been implemented for light oil as well. As the steam injection efficiency depend on temperature, both strategies (gravity drainage/ steam drive) take advantages of lower reservoir pressure to reduce steam generation cost as high quality-high temperature steam can be generated in low reservoir pressure regime.

As in other Enhanced Oil Recovery (EOR) project, in thermal operation, marginal economic is a major challenge to ensure sustainability of the project. The operational cost and oil price are determining factors. Material cost are the biggest portion in operational cost that must be maintained as low as possible. Steam

DOI: 10.25299/jeee.2023.14099
eISSN: 2540-9352 pISSN: 2301-8097

generation cost is generally the biggest portion of OPEX in a steamflood project. Optimization effort will be more important during low oil price and as the project matures since the production will decline while operation cost soars.

In a steamflood project, this can be achieved by managing injection rate. Steam-Oil-Ratio (SOR) is often used as a simple indicator/proxy of the economics of the project. Steam injection normally is ramped up until the targeted steam breakthrough (SBT), until which steam chest is fully developed (mature). The definition of thermal mature reservoir is as having characteristics below (Fram et al., 2002):

1) An overlying high mobility steam chest exists over the reservoir with the low pressure drop and constant temperature over a wide area.
2) The main mechanism operates for heating oil is conduction and convection with most of the heat from steam injection short circuits directly into the overlying steam chest.

In a heavy oil reservoir with steam injection, the driving force for oil production is the sum of three components: Gravity Drainage as the main component in a mature reservoir with the driving force is the oil column height, Steam Drag (with the driving force is the pressure gradient induced by steam and condensed steam moving in the steam chest) and Steam Drive (the driving force is from steam and condensed steam moving through the oil column) (Fram et al., 2002). For a mature reservoir, steam injection rate influences the gravity drainage component only indirectly via the steam chest temperature.

The oil production is normally peaking just before the Steam Breakthrough (SBT) and then start to decline. The injection rate would be then being stepped down to just enough rate to compensate heat lost (to overburden and under burden) in order to maintain steam chest that is already developed. Inability to inject enough steam will cause steam chest to shrink, lowering steam chest temperature and directly affecting oil production.

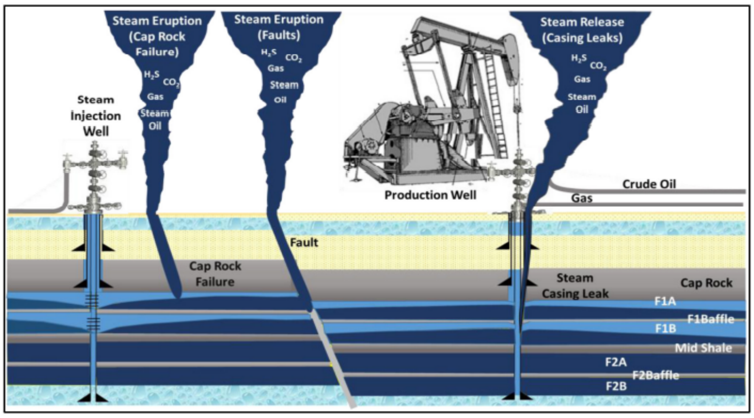

Figure 1. Steam eruption in Steamflood operation (Haider et al., 2015)

One limiting factor of production performance is the injection pressure which, especially during the ramp-up phase, the initial high injection pressure may not be acceptable as the steam chamber approaches the cap rock. The injection pressure will then have to be reduced to a lower value for safety reasons (Li et al., 2009).

As heavy oil is often present at shallow depth, the injection pressure is limited, for example Rindu formation in Duri field is found at 320 ft (figure-1). The injection pressure should be maintained below fracturing pressure which for area studied by is 0.725 psi/ft to avoid breaching the cap rock and creating environmental problem (Li et al., 2009). The lower pressure impact to lower the steam injection rate and subsequently the production rate.

In general, the caprock must have following criteria for thermal as below (Yi, 2008):

1. Constrain steam-chamber rise.
2. Prevent the loss of reservoir fluids to the overburden.
3. Prevent the ingress of cold water from above.
4. Prevent the development of excessive pressures in the overburden.
5. Withstand the existing and induced stresses and pressures over the life of the project.

Fault reactivation induced by excessive reservoir steam pressure in heavy oil fields can cause steam eruption to the surface, as occurred in Steam flooded Oilfield, including Duri field, Sumatra, Indonesia. Many of the steam eruptions were related to faults in addition to other factors such as poor cementing jobs (Yi,

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2008). This can lead to significant financial losses related to environment cleanup and curtailed oil production.

Generally, the higher the steam injection pressure, the shorter the ramp-up phase, and vice versa. However, the presence of poor-quality reservoir complicates the problem, where there is imbalance of injection and production so that reservoir pressure quickly goes up. Therefore, an accurate representation of depositional facies is needed to address and solve the problem.

One approach to mitigate the impacts of the problem is by modifying pattern size and utilizing horizontal well. Reduce pattern size will increase injection rate per areal and improve sweep. The size of the pattern will then be important to ensure production rates can be achieved during block contract period. If the areal pattern injection is large, the pattern thermal maturity (and associated production target) will take much longer to achieve.

METHODS

Preparation of Reservoir Model

A typical shallow reservoir in Duri field Sumatra encased in a 15.5 acre inverted 7-spot pattern is modelled using Builder-CMG. Combined with well data, fluid model and operating conditions (injection strategy, steam quality) and expected/ forecasted production. Rock thermal properties and fluid properties (oil, water) were using a dataset from Aziz's work (Aziz et al., 1987). CMOST package is then used to design history matching/ optimization study by varying the injection rate parameters and maximum allowable pressure and Cumulative SOR as history matching parameters. To achieve the objectives then it is divided into 2 main periods:

1) Initial injection to production peak by matching maximum frac allowed, and
2) Optimize Steam-Oil ratio from peak production to the economic limit.

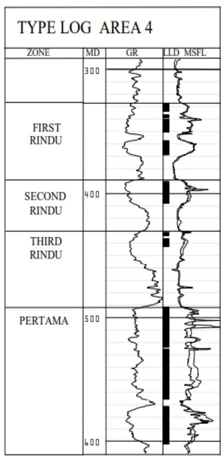


Figure 2. Typical Log Duri Field

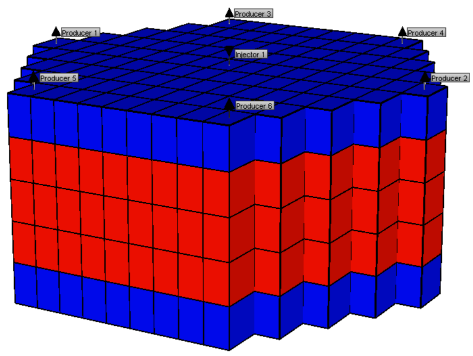
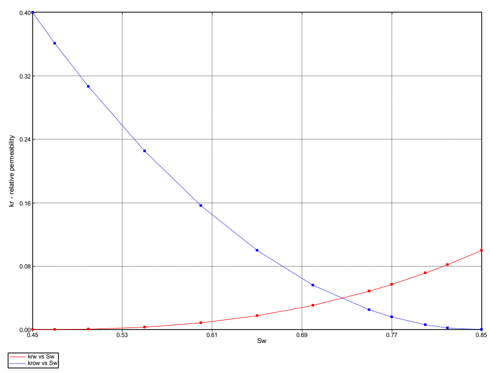


Figure 3. Regular inverted 7-spot pattern



Pseudo Comp	MW (lb/lb mole)	Density (lbmole/ft^3)	Liquid comp (1/psi)	Thermal expansion (1/F)
Water	18.02			
Light Oil	250	0.2092	5e-6	3.8e-4
Medium Oil	450	0.1281	5e-6	3.8e-4
Heavy Oil	600	0.102	5e-6	3.8e-4

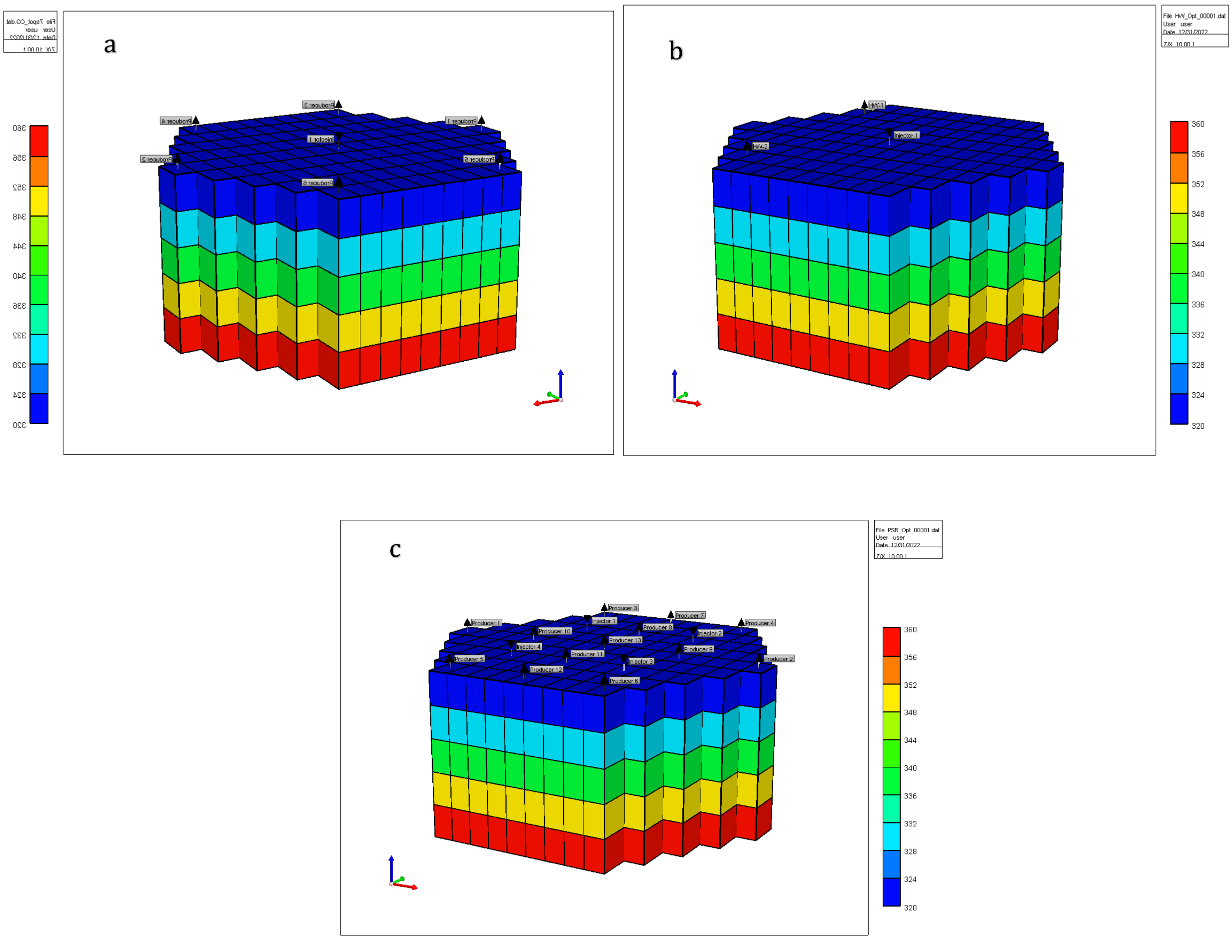


Figure 4. a. Regular 15.5 pattern
b. Horizontal well
c. Pattern size reduction

Table 1. Reservoir simulation model

Reservoir and Fluid properties	
Depth (ft)	320
Pay thickness (ft)	30
Porosity (%)	30
Horizontal Permeability (md)	200
Vertical Permeability (md)	20
Initial reservoir pressure (psi)	200
Heat capacity	
Thermal Conductivity	24
Oil compressibility (psi^{-1})	$5x10^{-6}$
Oil density (lb/cuft)	60.68

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Water density (lb/cuft)	63
Oil viscosity (cp)	5,780 cp @75 deg F
Operation Parameters	
Well spacing (acre)	15.5
Injector producer spacing (ft)	510
Steam quality (%)	70
Injection rate (BSPD)	200-3000 (ramp-up) 0-400 (maintenance rate)

RESULTS AND DISCUSSION

Impact of Injection Rate

In this research, we vary injection rate which is divided by two periods. Ramp-up periods starts from initial injection to achieve steam breakthrough (as indicated by reservoir temperature) and maintenance rate period from SBT to economic limit. Ramp up period is characterized by increased injection rate (stepped up), normally by carefully monitoring reservoir pressure as to avoid breaching the cap rock. After SBT is observed then normally oil production is at the peak, the injection rate is stepped down until the operational maintenance rate at 250 BSPD and the production continues to economic limit.

In normal depth pattern, injection rate can be achieved without problem, however at the very shallow depth, especially when reservoir quality is low, then injection target rate must be carefully managed by observing reservoir pressure. The reservoir studied is very shallow (320 ft) so that reservoir pressure must not higher than 209 psi.

To achieve the objectives then it is divided into 2 main periods:

1) Initial injection to production peak by adjustment to comply with maximum frac allowed, and
2) Optimize Steam-Oil ratio from peak production to the economic limit.

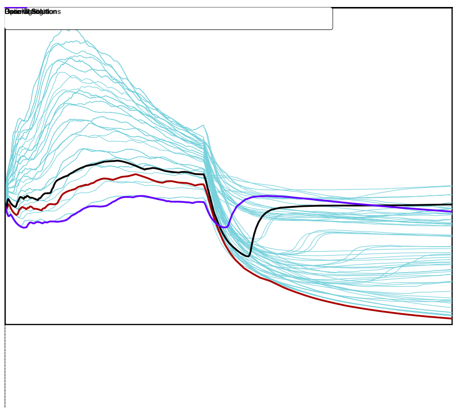

Figure 5.a Reservoir pressure scenario 1

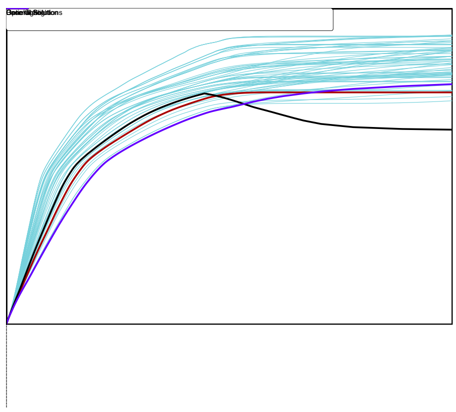

Figure 5.b Recovery factor scenario 1

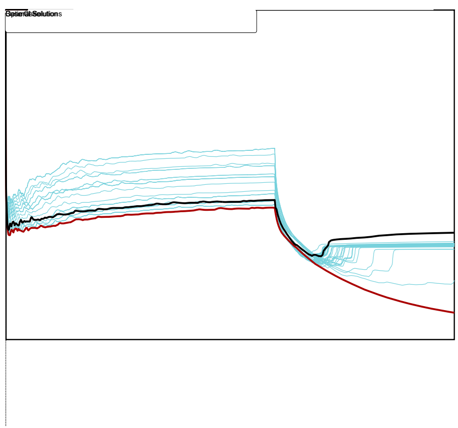

Figure 5.c Reservoir pressure scenario 2

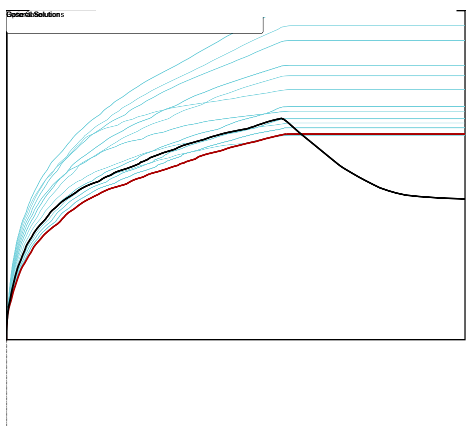

Figure 5.d Recovery factor scenario 2

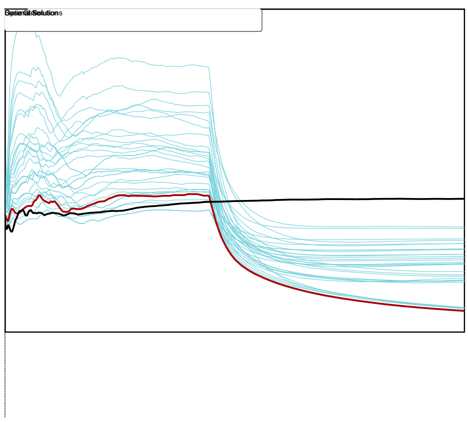

Figure 5.e Reservoir pressure scenario 1

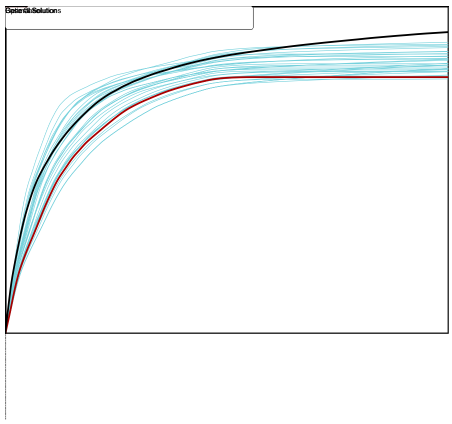

Figure 5.f Recovery factor scenario 3

We run sensitivity studies on all scenarios by varying injection rate and observe reservoir pressure and oil recovery factor. Objective function set for optimum case is to minimize Cumulative Steam-Oil-ratio (CSOR). A different water injection rate ranges are set for each scenario to account for different pattern acreage. Ramp up period (steam injection rate-1) is for four years followed by step down/ maintenance rate (steam injection rate-2) for five years.

Table 2. Rate sensitivity

Scenario	Steam injection rate-1 (BSPD)	Steam injection rate-2 (BSPD)
1	450-1200	0-200
2	450-3000	0-400
3	200-400	0-100

Table 3. Optimum cases for each scenario

Scenario	Cum SOR	Max Temp (°F)	Water Injection 1	Water injection 2	Max Press (psi)	Oil Recovery Factor (%)
1	1.58	212	525	0	153	73
2	5.6	195	705	0	58	61
3	2.7	250	240	0	150	78

We observe that optimum case for each scenario do not pressurize reservoir to be greater than 209 psi, with the scenario 2 (horizontal well) being the lowest pressure (the safest), hence it is possible to increase injection. Cumulative steam oil ratio as the proxy for economics show the lowest can be achieved by scenario 1. Horizontal well show the highest cum SOR perhaps due to the suboptimal number of wells in the pattern that affect sweep efficiency. Increase number of injectors in the pattern may help increase rate and production.

Oil recovery factor is achieved the highest using scenario 3 because smaller pattern size (acreage) increase sweep efficiency and maximum temperature although cum SOR is lower. All optimum cases show that it is better to shut in injection after breakthrough to maximize profit, perhaps due to reservoir temperature is still higher than the initial (heat mining effect).

CONCLUSION

We evaluate steamflood performance based on three criteria (Recovery factor, SOR and injection pressure compliance). Scenario-3 (Pattern Size Reduction) are able to inject twice as much steam rate as Scenario-1 with reservoir pressure difference ~10 psi only. The safest scenario in the sense that it will have no risk breaching cap rock is horizontal well scenario because it can be safely injected for a longer period of time without risking fracturing cap rock. In term of SOR (Steam Oil Ratio), Scenario-1 outperform the other scenarios while Horizontal Well being the highest SOR (lowest economic), however it must be noted that the number of horizontal wells may not be sufficient. Since injection rate is much higher and pattern is smaller (better sweep), Scenario-3 yield the highest recovery. In general, all scenarios result in better

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(lower) SOR with the injection rate cut to 0 after the production peak, without losing too much oil. The value of this study may lead to the optimization of the injection rateAcknowledgments to give better economics while minimizing the environmental risks.

Acknowledgments

This work was financially supported by Universitas Pertamina, Jakarta. Therefore, we are grateful for this funding and support of this research.

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