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Article

Simulation and Levelized Cost Analysis of Direct use Geothermal Energy for Enhanced Oil Recovery

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Abstract. To meet the demand for crude oil, which has a limited reserve; efforts are needed to maximize proven potentials. One of the solutions is the use of steam flooding as the most widely used Enhanced Oil Recovery (EOR) technology. However, the challenge that must be faced is the high production cost of steam which strongly depend on fuel cost. Meanwhile, the geothermal utilization in Indonesia is still low, only 9.3%. Seeing these problems and potential, it could be possible to utilize the geothermal heat for steam flooding. However, at present no research has been conducted related to geothermal utilization for steam flooding, only for water flooding. Therefore, this study is aimed to evaluate geothermal heat utilization for steam flooding by evaluating the maximum distance between geothermal and oil field, evaluating the technical aspect by using Honeywell UniSim Design and CMG Star and reviewing the levelized cost of steam. The results that geothermal heat can be used economically and technically possible as a pre-heating system before the boiler and it reduces the cost of steam production by 12% with a maximum distance between geothermal and oil field of 30.1 km.

Keywords: Enhanced oil recovery (EOR), steam flooding, geothermal waste heat.

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1. Introduction

Crude oil plays a vital role in Indonesia's energy supply. In 2018, as much as 38.81% of the national energy mix is still dominated by crude oil [1]. If this dependency continues and follow with an increase in energy demand, the crude oil reserve will be depleted. Currently, there has been a decrease in crude oil reserves by 157.2 MMSTB in 2016 compared to 2012. In addition, exploration activities are now only carried out in 34 wells with the discovery of nine new wells or it can be concluded that the success ratio is only 26%. This value decreased compared to 2012, which reached 37% [2]. The way to deal with this is to import the crude oil. Indonesia's crude oil imports in 2016 increased by 55% compared to 2012 [2]. Limitations in the discovery of new wells and there is no guarantee that all new wells can be produced commercially, causing the need to maximize the utilization of proven sources. This is because when the production process takes place, only about 35-45% of the oil can be produced from the total oil in place for primary and secondary methods [3]. To maximize production, a tertiary method, called enhanced oil recovery (EOR), is carried out. The most extensive use of EOR is steam flooding which has the 60% of recovery factor because of effectiveness and relative ease of operation [4-6]. Steam flooding can increase oil production through continuous injection of steam into injection wells by reducing the oil viscosity and generating an artificial drive that sweeps oil towards producing wells [7]. When the oil viscosity has decreased and steam will replace oil in the reservoir, the oil will be easier to mobilize toward the production well. Steam flooding is suitable for heavy and shallow oil fields. In Indonesia, the steam flooding application has been carried out at Duri Field, known as Duri Steam Flooding Project (DSF) [6]. DSF has a contribution of 20% to national oil production [8]. The challenge of steam flooding is the high steam demand which results in a surge in operating cost [9]. For example, in California, the ratio of oil produced to steam is 0.25 [9]. The fuel cost is highly dependent on fuel price [10]. The fuel used in boilers for steam flooding is natural gas [11]. With natural gas reserves starting to decrease [12] and the price increases every year, resulting in economic constraints in its operation in addition to the fact that steam flooding is long-term project (DSF has been operated for more 30 years [10, 13]. In addition, according to Ali, S.M.F (2003) other obstacle in the operation of gas-based boiler is environmental issue [9].

Meanwhile, Indonesia as a country in the Pacific Ring of Fire has been granted 40% of the world's geothermal potential, equivalent to 25,3 GWe [1]. However, currently, geothermal utilization is still very small at 9.3% [14]. This utilization is still centralized for electricity generation, while utilization for other sectors is still low [1]. The challenge in geothermal utilization is that it is site specific and cannot be distributed; therefore, the distance between geothermal field and user location that are translated into piping systems becomes very vital to be studied. Seeing these problems and Indonesia's potential, it could be possible to utilize the geothermal heat for steam flooding.

At present there are several researches related to the economics of steam production and renewable energy utilization for steam flooding [15, 16]. C. Afsar and S. Akin (2016) and M. M. Yegane, et al. (2015) investigated the potential use of solar energy for boilers. Meanwhile, the utilization of geothermal energy was investigated by L. R. a. S. Z. Liu Junrong (2015) and S. J. S. a. T. G. Walter (1994) [17, 18]. However, they investigated the potential use of geothermal brine for water flooding on adjacent geothermal and oil field. The study of geothermal utilization for steam flooding is still unavailable. Therefore, this study is aimed to evaluate geothermal heat utilization for steam flooding by evaluating the maximum distance that can be taken to apply the integration of the geothermal and oil field, evaluating the technical aspect by using Honeywell UniSim Design and CMG Star, reviewing the levelized cost of steam.

2. Methodology

This research is divided into two steps, which are process simulation, and levelized cost analysis. The process simulation is to evaluate the possibility of geothermal utilization start from the wellhead of the geothermal field to the injection well using Honeywell UniSim Design. In this simulation, the specifications of the steam to be injected into the oil well are set. In order to ensure that the assumption of constant steam injection operation conditions does not have a significant impact on the level of oil recovery, a sensitivity analysis regarding temperature and pressure is carried out on the steam flooding process using CMG Star. Furthermore, the economic analysis was carried out through the levelized cost of steam (LCOS) analysis to evaluate whether the proposed scheme is more favorable than the existing scheme. Therefore, the selected scheme will be determined from the technical and economic aspects. Moreover, the selected scheme is evaluated to be applied in Indonesian by reviewing the maximum distance from geothermal fields and oil fields to be integrated.

2.1. Case Study

The system considered in this study is the process of utilizing heat from geothermal source, the distribution of steam into the injection well on the oil field, and steam flooding process. The geothermal field data used is Silangkitang Field (SIL-1) Sarulla which is water dominated geothermal field as the most common field type in Indonesia. Field SIL-1 has 213°C with a pressure of 20 bar steam at well head [18]. A typical minimum steam flooding operating condition shown in Table 1 and typical reservoir data refer to Mozzafari, S (2013) [21].

Table 1. Steam specification data for injection well [21].

Steam Parameter	Value
Steam flowrate (kg/day/well)	453
Steam pressure (bar)	24-30
Steam temperature (°C)	228

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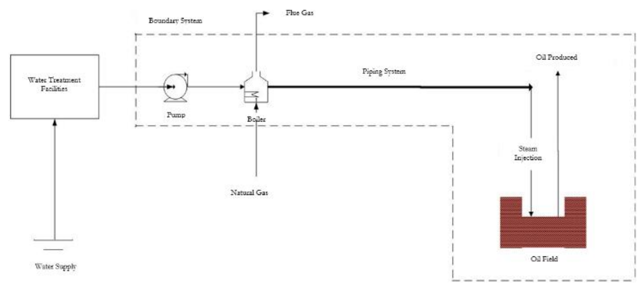
2.2. Steam Supply System Simulation

This section evaluates the possibility of geothermal utilization, which is technically evaluated by process simulation to meet existing specifications. The simulation was carried out for three scenarios that would affect the production system of steam itself as shown in Table 2 and Fig. 1.

Table 2. Simulation scheme.

Scheme	Description	Pump	Boiler	Heat Exchanger	Piping
1	Steam production process by using conventional boiler	√	√		√
2	Steam production process by utilizing geothermal heat	√		√	√
3	Steam production process by combining conventional boiler and geothermal heat	√	√	√	√



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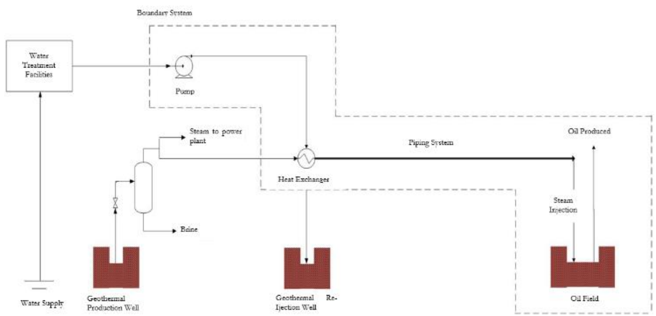

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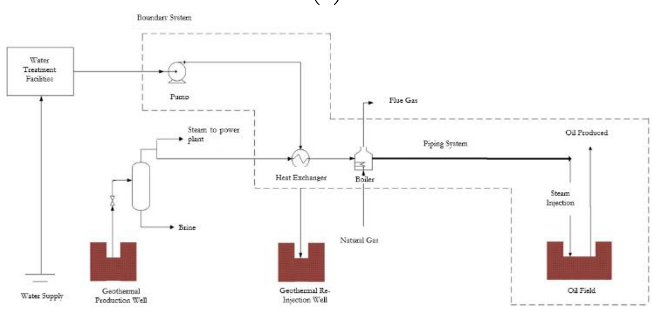


(c)

Fig. 1. Integration system (a) scheme 1; (b) scheme 2; (c) scheme 3.

Scheme 1 (Fig. 1a) is a base scheme which represents the current condition of steam production using natural gas. This scheme is simulated as a comparison of economic evaluations. Scheme 2 (Fig. 1b) reviews the geothermal potential to completely replace the role of the boiler and Scheme 3 (Fig. 1c) reviews the potential of geothermal energy as a pre-heater if in Scheme 2 the energy in geothermal energy is not sufficient to produce the desired steam. The assumptions used for this simulation are as follows:

1. Steam pressure, flow rate, and temperature at the geothermal well head are based on typical geothermal field data for liquid domination systems.
2. Piping is considered straight, there is no fitting or elevation
3. Components involved in the simulation system are pure water (there are no impurities in the water supplied either in supplied water or geothermal steam)

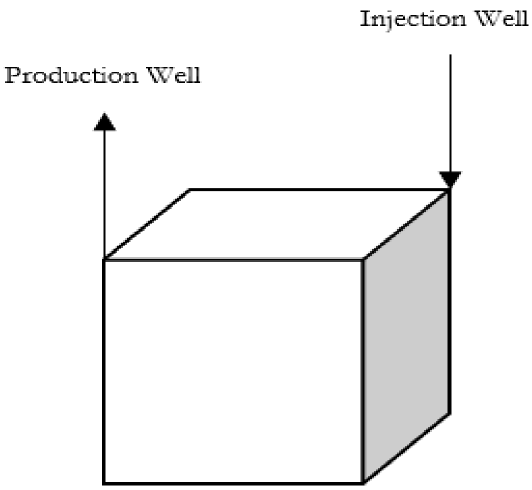
In addition to the variation of the scheme, this study reviewed variations in changes in pump output pressure of 28, 30, 32 bar.

2.3. Steam Flooding Simulation

Steam flooding simulation is done by validating the reservoir data and the simulating the entire process itself. The assumptions used for this simulation are as follows:

1. The phases involved are oil, water and gas (3 phases)
2. Reservoir modeling is done in 3 dimensions
3. The 3 phases relative permeability effect are involved
4. Capillary pressure effects are not involved
5. Oil is assumed to be a non-volatile component
6. The coefficient of thermal conductivity of reservoir rocks in the upper and lower layers is constant
7. The injection system is ¼ - 5 points for validation and 5 points for simulation
8. Only one oil production simulated

Validation of reservoir data is done by evaluating cumulative oil production profile against the time using a quarter-five spot injection (see Fig. 2a) with the Mozzafari, S (2013) result. Then, the steam flooding simulation was carried out in a system consist of 1 production oil well with 4 steam injection wells or five spot injection (see Fig. 2b) [21]. This simulation is carried out with the temperature variation (222°C; 232°C; and 336°C) with a pressure of 26 bar and the steam pressure variation (24; 26; and 29 bar) with 232°C.



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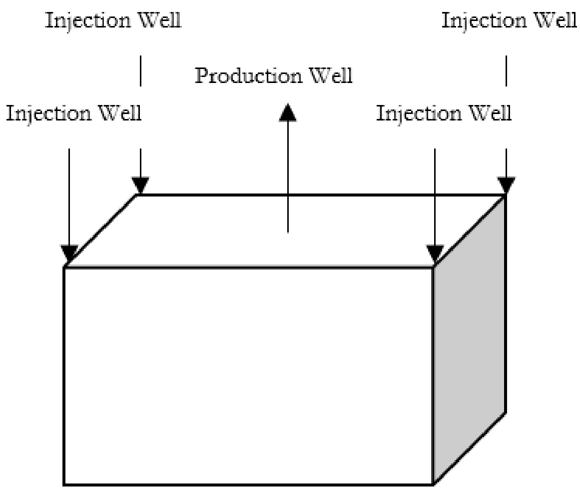


(b)

Fig. 2. (a) System built for validation (quarter-five spot); (b) System built for simulation (five spot).

2.4. Levelized Cost of Analysis

Economic evaluation is carried out using the levelized cost of steam (LCOS) supply for EOR as described in Equations 1 and 2 with CAPEX is the investment cost, OPEX is fixed operation and maintenance cost, FC is the fuel cost, *r* is discount rate, and *n* is the amount of annualized year. Investment costs will be annualized using the cost recovery factor (CRF).

$$\text{LCOE}=\frac{\text{CAPEX}\times\text{CRF}}{8760\ \text{CF}}+\text{OPEX}+\text{FC} \quad (1)$$

$$\text{CRF}=\frac{r(1+r)^n}{(1+r)^n-1} \quad (2)$$

The calculation of investment cost is referring to the simulation result. The assumption of economic analysis conducted shown in Table 3.

Table 3. Economic Assumption.

Economic Parameter	Value
The integration system lifetime	20 year
Natural gas price	US$7/MMTBU
Discount rate	10%

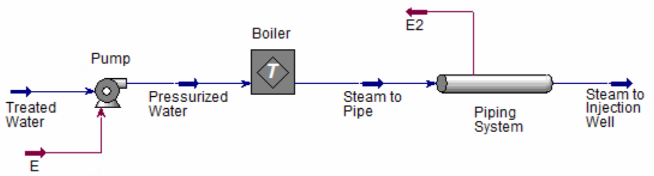
2.5. Integration System Evaluation

Considering that geothermal utilization needs to review the distance of the field to the oil field, a simulation is performed on the maximum pipe distance with the quality of steam at the end point of the pipe or at the head of the oil field well is saturated. This is done by setting the vapor fraction = 1. In addition, the injection pressure is set to be 24 bar as the lowest injection requirement pressure (See Table 1).

3. Result and Discussion

3.1. Steam Production Scheme

The simulation results of the steam production system based on Fig. 3 are shown in Table 4.



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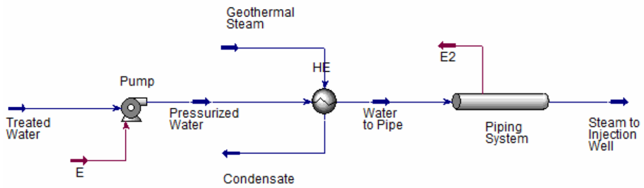

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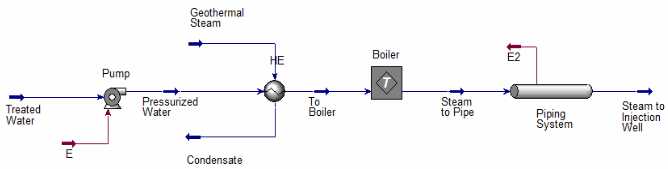

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Fig. 3. Steam production simulation (a) scheme 1; (b) scheme 2; (c) scheme 3.

Table 4. Integration system simulation result.

Scheme	Temperature (°C)	Outlet Pressure (bar)	Vapor Fraction	Natural Gas Consumption (MMBTU/day)
1	485	28	1	511,72
2	202	28	0	-
3	456	28	1	375,01

Scheme 1 shows the requirement of natural gas to produce steam in order to meets the appropriate specifications based on Table 1 is 512 MMBTU/day. Meanwhile in Scheme 2, it can be seen that there is no steam formed in the heating process that relies on fully geothermal energy because the heat contained in geothermal steams is not able to change the water phase due to higher water pressure than the geothermal steam pressure. Geothermal steam pressure is only 20 bar, while the water has a pressure of 28-32 bar. The higher the water pressure, the higher the temperature needed to convert the liquid phase into the vapor phase. More energy is needed to make the water vapor pressure equal to the water pressure, therefor phase change cannot occur. For this reason, it can be said that Scheme 2 cannot be applied in terms of technical aspect. Meanwhile in Schemes 3, steam can be produced with 375 MMBTU/day of natural gas or 26,7% lower than in Scheme 1 which the reduction shows the load that is fulfilled by pre-heating system using geothermal energy.

3.2. Steam Flooding Evaluation

3.2.1. Reservoir Validation

Simulations for reservoir data validation and validation results are shown in Fig. 4 and Fig 5, respectively. Figure 4 shows the steam and oil saturation profile in reservoir grid at the 33rd day and 365th day. The steam saturation at 365th day is higher throughout the reservoir grid compare to 33rd day. It is because at the 33rd day the amount steam injected is still low. Otherwise the oil saturation is lower at 365th day compare to 33rd day. It is because at 33rd, the production of oil caused by steam injection is still low. From Fig 4c, it can be seen that the oil is flow to the production well, as production well grid shows higher saturation rate. This shows how steam in drive the oil production.

Based on Fig. 5, the breakthrough time shown in the simulation is 280 days, while in the literature shows 250 days. This difference is only 12%. However, in the simulation and reference, there is slight difference in oil recovery. This happens because there are several different input data between simulation and reference, including the correlation equation of oil viscosity, well completion, and porosity which are considered constant in this simulation. In the reference a lot of data is not shown, for which the data is assumed. The correlation equation of oil viscosity is basically specific to an oil field. The equation used uses the heavy oil correlation equation obtained from the CMG module on different oil fields. This difference in the correlation equation causes different amounts of oil produced. This might happen due to the decrease in oil viscosity to temperature. In addition, the design of well completion is not stated. Well compression is related to the length of perforation from production wells and injection wells and pressure inside the well. When the perforation of the well is large and is spread along the pipe, the fall of pressure from the reservoir will be greater due to the production process which decreases reservoir pressure. This reduction in pressure causes insufficient pressure in the reservoir to produce oil that is still trapped in the reservoir.

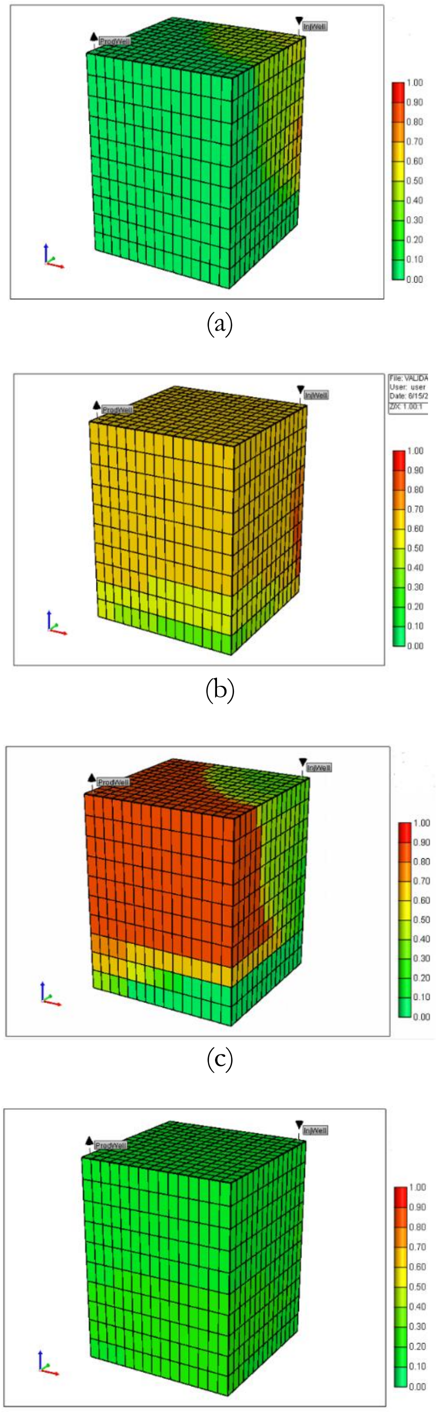

Fig. 4. Steam saturation at (a) 33rd day; (b) 365th day; oil saturation at (c) 33rd day; (d) 365th day.

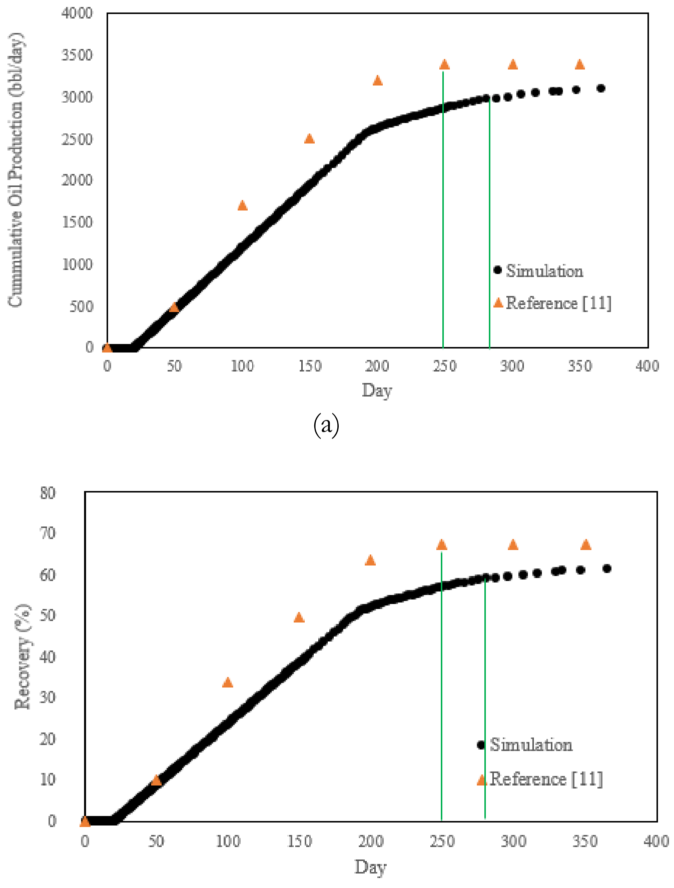

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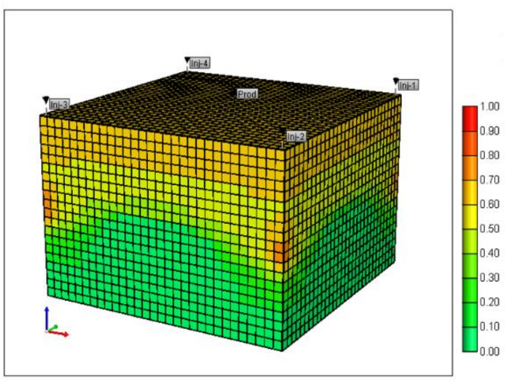
Fig. 5. Validation: cumulative (a) oil production; (b) oil recovery.

3.2.2. Injection Temperature Effect

Figure 6 shows the steam and oil saturation the 77th day at various injection temperatures. It shows that the higher the steam injection temperature, the faster oil will be produced from the reservoir. This can be seen from the small saturation value of oil at high temperatures compared to low temperatures in the same time base. This is because steam will more effectively heat oil which causes lower oil viscosity, making mobilization easier. The cumulative oil production and recovery throughout the entire lifetime at various injection temperatures are shown in Fig. 7.



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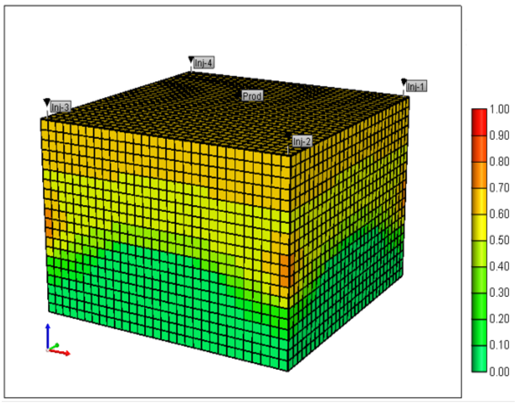

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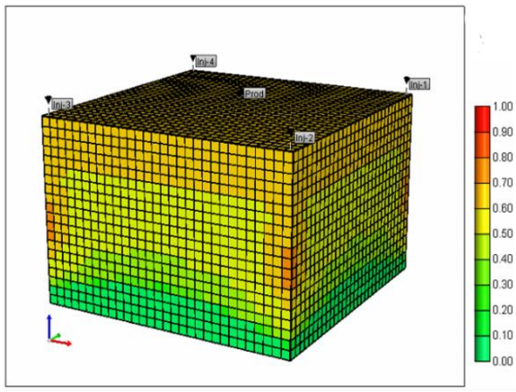

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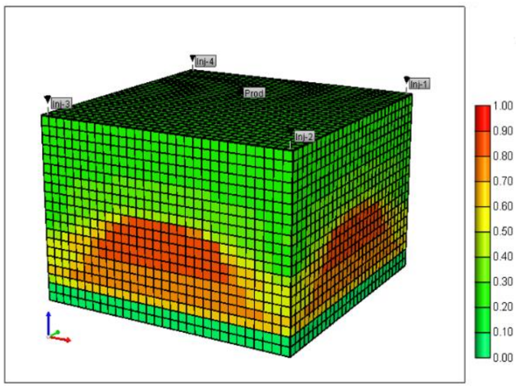

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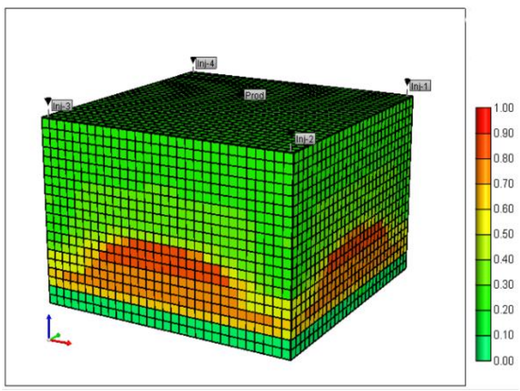

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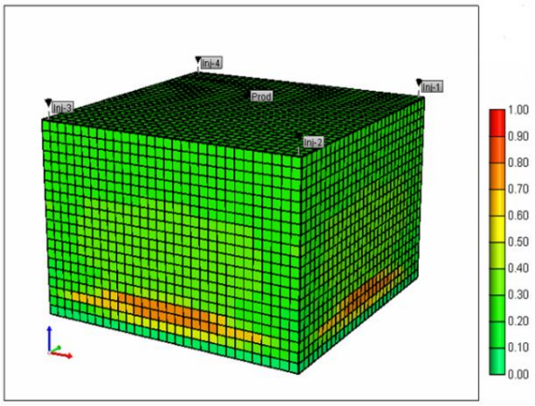

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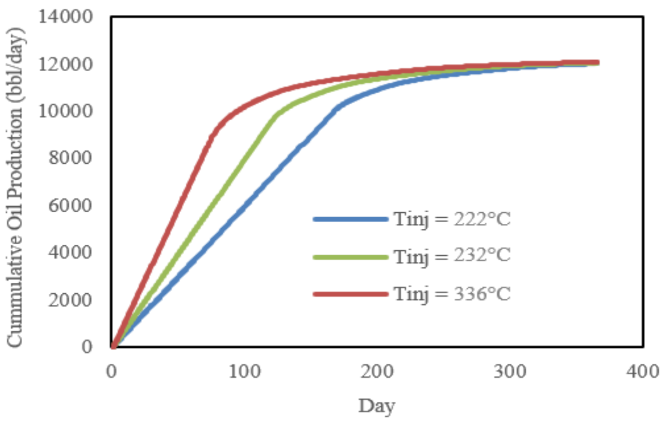
Fig. 6. Simulation result: steam saturation injection temperature (a) 222°C; (b) 232°C; (c) 336°C; and oil saturation injection temperature (a) 222°C; (b) 232°C; (c) 336°C.



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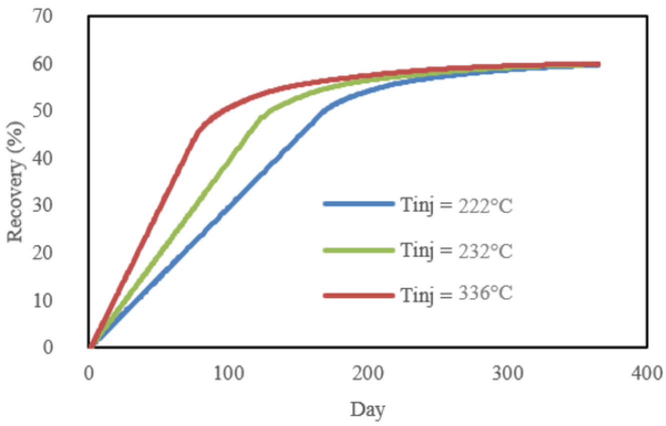
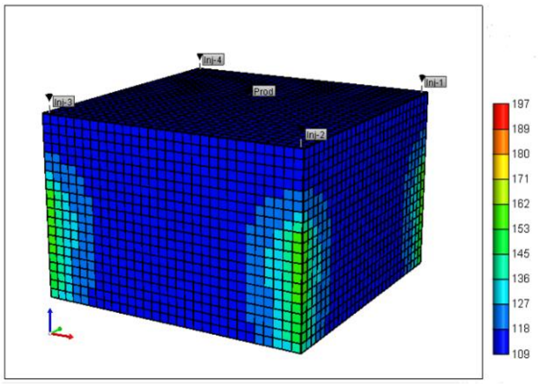


(b)

Fig. 7 Cumulative oil production (a) and recovery (b) for injection temperature variation.

Based on Fig. 6, it can be concluded that the breakthrough time produced in variations of 222, 232, and 336°C is 180, 134, and 85, respectively. It is because higher temperature, the higher heat carried by steam, more sufficiently the steam expands in vertical and horizontal directions (see Fig. 8), faster the temperature front, lower oil viscosity and gas saturation front move, [22]. Therefore, smaller the breakthrough time shows the cumulative oil production per unit time will be greater at higher temperatures. Therefore, any changes every 1°C of steam temperature will only affect the maximum breakthrough time of 1.7 days.



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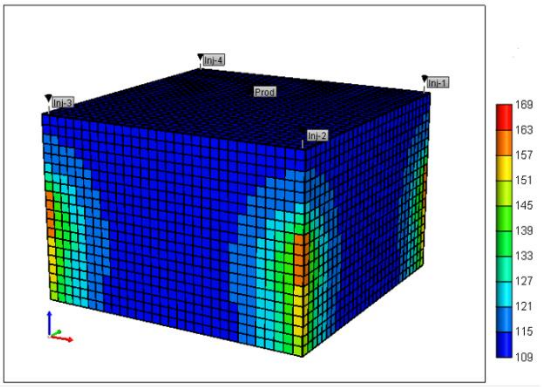

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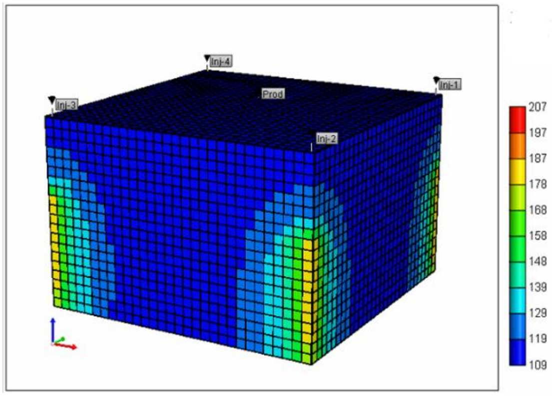
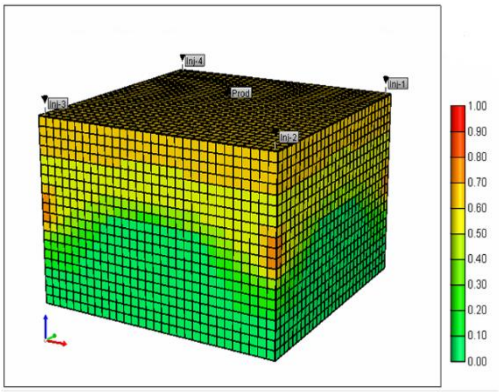


(c)

Fig. 8. Temperature profile at 30th day at various injection temperature (a) 433; (b) 450; (c) 638°F.

3.2.3. Injection Pressure Effect

Figure 9 shows the steam and oil saturation the 147th day at various injection pressures.



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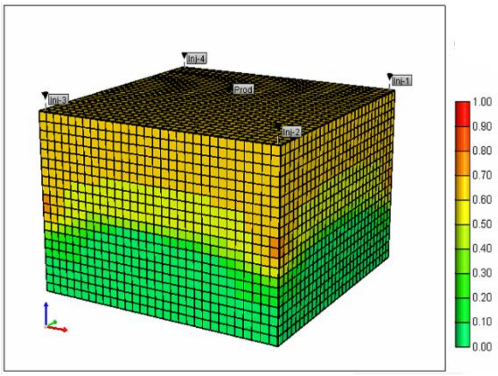

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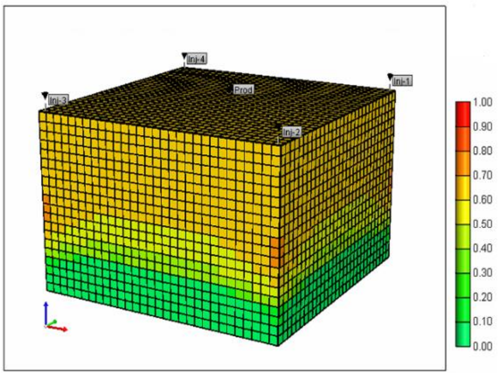

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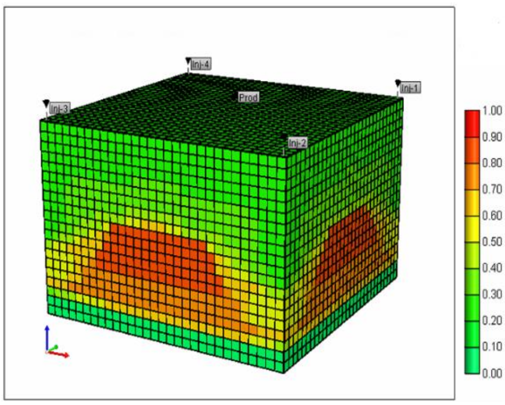

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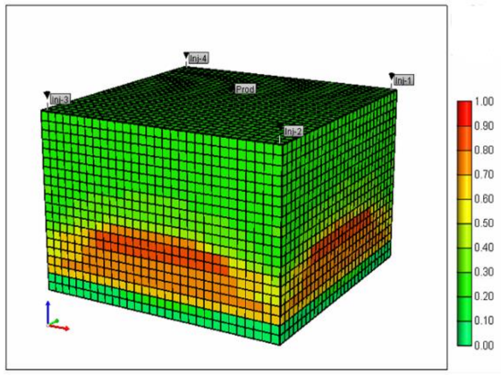

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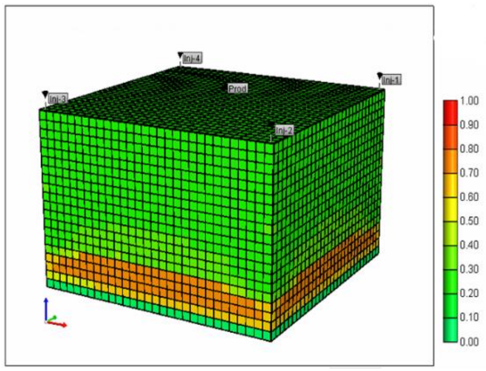
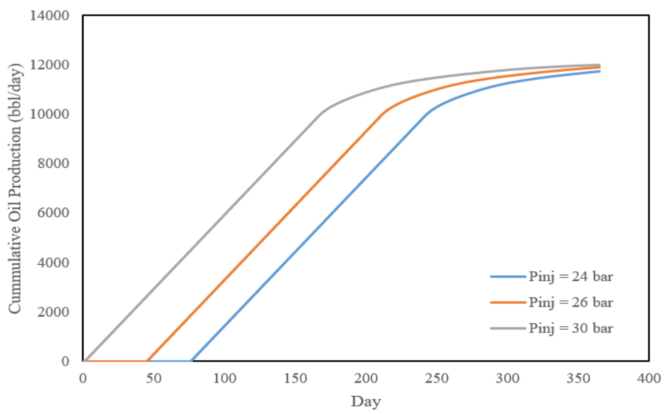


(f)

Fig. 9. Simulation result: steam saturation injection pressure (a) 24; (b) 26; (c) 29 bar; and oil saturation injection pressure (a) 24; (b) 26; (c) 29 bar.

Based on Fig. 9, the higher injection pressure, the higher oil leaving the reservoir as it can be seen in lower oil saturation value at the same point and time. This is because steam puts enough pressure on the reservoir to produce oil, thus the displacement mechanism is occurred. Figure 8 shows the cumulative oil production and recovery for pressure variation. It shows the breakthrough time for injection pressure variation 24, 26, and 30 bar is 249, 219, dan 177 days, respectively. If the pressure changes aroud 1 bar, the breakthrough curve will change 10 days.



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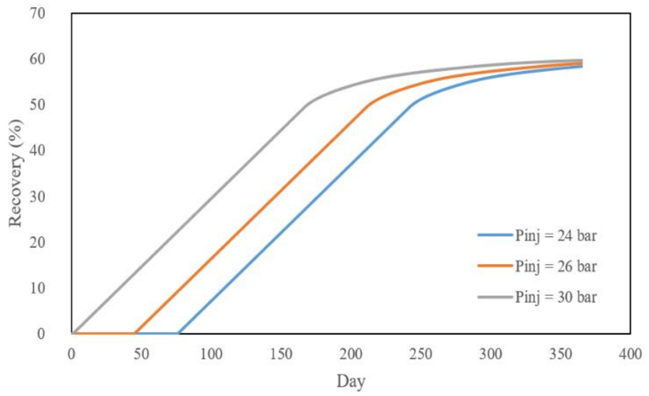

(b)

Fig. 10. Cumulative oil production (a) and recovery; (b) for injection pressure variation.

From Fig. 7 and Fig. 10, it can be concluded that the impact of changes in injection pressure is more significant than changes in temperature. However, changes in these two parameters do not affect the rate of oil recovery, only slightly affecting the breakthrough time. For this reason, the assumption of constant steam flooding conditions in the integration system simulation does not affect the performance of steam flooding.

3.3. Levelized Cost Analysis

From Schemes 1 and 3 that are technically possible, an economic evaluation of both is done to assess the best scheme. Figure 11 shows levelized cost of steam in the variation of water pressure from pump.

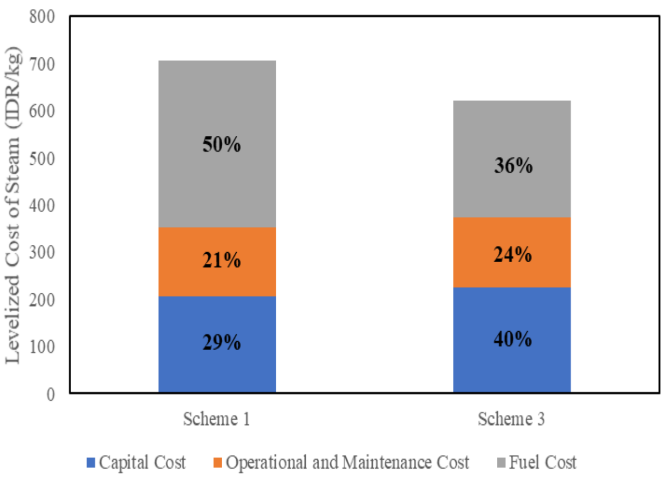

Fig. 11. Cost breakdown for steam production.

Scheme 1 and 3 generates steam cost IDR707/kg and IDR 622/kg, respectively. It shows that the utilization of geothermal heat causes 12% cost saving in fuel cost, even though there is an additional capital investment. This is because fuel cost affects the final price more than the investment cost. For this reason, it can be concluded that Scheme 3 is the best scheme both technically and economically.

3.4. Distance Evaluation for System Integration

Along with the use of geothermal energy is technically and economically beneficial (Scheme 3), it is important to simulate the maximum distance that allows for the integration of the two fields. Figure 12 show the simulation about the effect of various steam injection pressure to the pipe length. Based on Fig. 12, higher injection pressure requirement for steam flooding leads to shorter pipe length to produce saturated steam. It is because the higher pipe length leads to the higher pressure drop in piping system. As stated in previous section, that the must be supplied in saturated condition at the end of the pipeline system and at lowest injection pressure requirement, the simulation shows that the maximum of piping system is 30.1 km with steam injection temperature 231°C as the closest temperature to the literature data (Table 1).

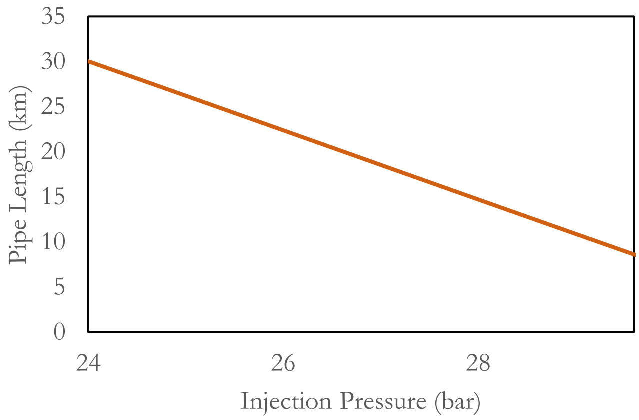

Fig. 12. Maximum pipe length to supply saturated steam at oil well head.

Referring to the current condition and take the SIL-1 Field as reference, Table 5 shows the nearest oil field.

Table 5. The distance between nearest oil field and SIL-1. geothermal field.

Oil Field	**Location**	**Distance from SIL-1 (km)**
Duri	Sumatra	250.86
Minas	Sumatra	293.18
Kaji	Sumatra	805.54

From Table 5, it can be seen that Duri as the closest oil field to Sarulla which has a distance of 8 times compared to the maximum distance. For this reason, referring to the current conditions, there is no geothermal field whose distance is below 30.1 km. However, it does not rule out the possibility that in the future there is geothermal field located near heavy oil field.

4. Conclusion

Based on this study, it can be concluded that the most possible and economic integration system to be implemented is the utilization of geothermal energy as a pre-heater in the boiler steam generator that can reduce 12% of the overall steam production cost. The maximum distance for integration system between geothermal and oil field is 30.1 km. However, currently, there is no location for the two fields below that maximum distance. Perhaps in the future this study can be taken into consideration if geothermal potential is found adjacent to heavy oil fields.

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