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A novel technique combining the cyclic steam stimulation and top gas injection for increasing heat efficiency

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ABSTRACT

In the first production period of cyclic steam stimulation (CSS), the oil production rate becomes high due to reducing oil viscosity and increasing reservoir. Even though the remaining heat is still available in the surroundings of the well, the production rate declines too sharply resulting from the reservoir pressure reduction. This paper aims to maintain the oil production rate, which utilizes the remaining heat in the reservoir with a gas top injection. After the oil production rate declines, the gas is injected into the top side of the formation which pushes crude oil to the lower part of the reservoir. Finally, the crude oil moves to the production perforation. The result indicates that the optimum volume gas injection is 6500 MMSCF. In such method, increasing reservoir thickness will be more favorable because the gas spreads more laterally and dissolves to the oil phase. In the case of extended cycle production time, the steam effectiveness will increase. To get the most favorable operation condition, the reservoir thickness must be more than 20 ft. In the optimum case, the cumulative oil production increases 3.5 times and the cumulative steam oil ratio decreases 60% compared to CSS-conventional.

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Reservoir simulation; thermal recovery; cyclic steam stimulation; top gas injection; heat efficiency

1. Introduction

The innovation of modified bitumen and heavy oil recovery is continuing further development. The bitumen and heavy oil recovery have been successfully applied in steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), steam flooding, and non-thermal recovery methods. The optimization of the SAGD method has been studied by researchers through laboratory study and numerical simulation (Barillas, Dutrajr, & Mata, 2006; Li, Chan, & Froehlich, 2009; Nasr, Golbeck, Korpany, & Pierce, 1997; Suranto, Bae, & Permadi, 2015; Suranto, Permadi, Bae, Park, & Son, 2016a; Tamer, & Gates, 2012). In one such method, CSS has been successfully applied to transfer the heat to the reservoir by injecting steam periodically into the production well. This method was first applied in the late 1950s to recover bitumen from the tar sands of Venezuela. In some cases, the recovery factor could be more than 20% as reported by Esso, or it could become lower than 20% as reported by some projects in Cold Lake, Canada (Hong, 1994).

In the first CSS process, the oil production rate is normally high due to low oil viscosity, high reservoir pressure, and high initial oil saturation (Sheng, 2013). And then the well possibly produced for several months. After several cycles, the oil saturation gradually decreases in the surrounding area near the wellbore. This area should not be the target of heating, but the area further away from the borehole instead. To reach such target, the steam volume will obviously increase. Consequently, the cumulative steam oil ratio (CSOR) will increase indicating that the process is no longer efficient.

To improve the disability of the conventional CSS process, various techniques have been reported to be successful. The optimization of the operating conditions including steam injection rate, steam quality, and soaking time can also increase the oil production and reduce the CSOR (Azad, Alnuaim, & Awotunde, 2013; Ho & Morgan, 1990). Thereafter, increasing the ultimate recovery using gravity drainage effect has demonstrated to be successful in the Xing VI Formation. In such case, adding horizontal wells in the bottom of the vertical well during CSS process will increase the oil recovery (Liu, Ren, Bao, Yang, & Ma, 2003). Furthermore, injecting nitrogen before CSS assists the process and conducts better results (Du, Wang, Jiang, Ge, & Zhang, 2013).

Comparable with the SAGD process, the gas top injection has been initiated by Butler in Butler, 1999. In

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this research, the steam and gas push (SAGP) should be practical in the specific condition reservoir. In the further development research, the oil production rates for SAGP process are slightly lower than SAGD but its steam oil ratio (SOR) is much lower due to lower steam injection rates (Jiang, Butler, & Yee, 2000). On the other side, the top gas injection in the SAGD wind-down has been investigated and found that this method could recover approximately 12.5% of OOIP (original oil in place) by maintaining oil production rate (Zhao et al., 2005).

Proportional with the CSS method, the separation of perforations to be a top injection and a bottom production will improve approximately 30% compared with conventional CSS (Suranto, Permadi, & Bae, 2016b). Here, steam is injected into the top perforation. Therefore, the steam would condense because of the heat loss to the reservoir, and finally, it would flow to the lower part because of gravity force. Hereafter, the oil is produced through the bottom perforation. Even though this method has been feasibly applied using reservoir simulation study, this method needs an equipment called interval control valve (ICV). To minimize this flaw, a novel technique combining the CSS and gas top injection is proposed and investigated in this research.

This research studied how to utilize the remaining heat after CSS process and maintain the reservoir pressure by gas. This method consists of two perforation sections, the first section is at the top as gas injection and the second section is at the bottom as CSS process. In this process, after the steam is injected into the bottom perforation section, the steam would condense because of heat loss to the reservoir (soaking time period). Hereafter, the oil is produced through the production section (still on the lower section). During the production period, even so, the remaining heat is still available in the surroundings of the well, the reservoir pressure drops and the production rate declines. To overcome this phenomenon, the gas is injected to the top side of the reservoir during the production period. The function of gas injection is maintaining pressure to utilize remaining heat. In such cases, the oil production rate can be held up longer. Consequently, the effectiveness of steam in this process is better than that of the conventional CSS.

2. Well completion for utilizing remaining heat and gas top injection

The rule of thumb of the CSS perforation is one-half bottom formation target. This role maintains steam gravity override and eliminates heat loss in the overburden of the reservoir (Sheng, 2013). Figure 1(a) and (b) show that the CSS conventional perforation is half of reservoir thickness from bottom side. The packer is installed on the top of that. The steam is injected in this perforation and also the production fluid is produced in the same perforation. Figure 1c displays the perforation of CSS-gas top injection. In the top side after CSS perforation is done approximately an eighth part from the top reservoir as for the gas injection.

The process of CSS conventional is that steam is injected into the reservoir, soaking time, and heavy oil production. In the CSS-gas top injection, during the production period, methane is injected to the top side of the reservoir and the gas pushes the oil to the lower part of the reservoir. Because the surroundings of well still has heat remaining, the viscosity of heavy oil does not return to its original condition yet. And then, the heavy oil can be produced more.

3. Description of reservoir model

The thermal reservoir simulator, STARS Version 2015 by Computer Modeling Group is used to construct the reservoir model. The model is used to investigate the performance of conventional CSS and CSS-gas top injection. A reservoir model represents generic Pertama and Kedua

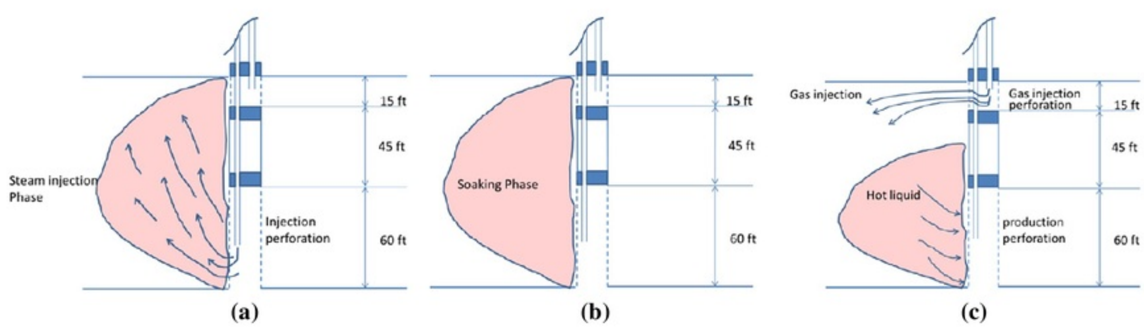

Figure 1. Completion modified for CSS-gas top injection. (a) The steam injection period, (b) Soaking time period, (c) The CCS-gas top injection period.

Formations in Duri Field, Indonesia. It consists of one vertical well in the center of a radial system. Table 1 shows the pertinent reservoir properties that were used in this research.

There were no gas cap and bottom water driving mechanisms. The boundary condition was no-flow. The geo-mechanicals effects such as dilation related to pressure or temperature were also ignored. Due to limited data, the rock and fluid properties are assumed to be homogeneous in the whole reservoir. The oil column thickness is constant for all layers. The ratio of the horizontal permeability to the vertical permeability is 0.5.

The ratios of the mole fraction of methane in the vapor to the soluble in crude oil are represented by K-values. In such blend, only the soluble methane (gas) will reduce the bitumen viscosity while the vapor fluid will increase the reservoir pressure. The reservoir simulation works in the both fluids. The K-value is a function of temperature, pressure, and some coefficients as shown in Table 1. In this study, the coefficient of Kv1, Kv2, Kv3, and Kv5 refer to the STARS manual (CMG, 2015).

The number of the grid is 22 × 4 × 40 (i, θ, k). The near-wellbore grid size was 3 ft and gradually increased toward the reservoir boundary to reach the value of 330 ft while the vertical grid size was kept constant at 3 ft. The injection steam quality was equal to 0.8 and the steam temperature is 432 °F. The conventional CSS and CSS-gas top injection processes were simulated using this reservoir model. In those processes, the steam injection pressure at the sand face was kept constant at 350 psi and the maximum steam injection rate (equivalent water) was 600 STB/day. During the production period, the minimum bottom-hole pressure (BHP) is set to be 70 psi which is generally reasonable for pump operations.

Table 1. Pertama/Kedua reservoir properties (Gael, Gross, & McNaboe, 1995).

Reservoir properties	Value
Depth, ft	500
Initial reservoir temperature, °F	100
Initial reservoir pressure, psi	100
Net thickness, ft	120
Reservoir radius, ft	200
Porosity, %	0.34
Permeability, mD	1500
k_v/k_h, fraction	0.5
Rock compressibility, 1/psi	5.7e−6
Oil density, °API	20
Oil viscosity at reservoir condition, cP	330
Oil viscosity at 432 °F, cP	8.2
Oil formation volume factor at reservoir condition, RB/STB	1.02
Solution gas-oil ratio, SCF/STB	14
Residual oil saturation to water, fraction	0.25
Residual oil saturation to steam, fraction	0.1
Irreducible water saturation, fraction	0.40
Reservoir, underburden/overburden volumetric heat capacity, BTU/ft^3–°F	33.2
Reservoir, underburden/overburden thermal conductivity, BTU/ft–day–°F	27.4
Methane K-value correlation, $K_{\text{-value}} = \frac{kV_1}{p} e^{\frac{K_{v4}}{T+K_{v5}}}$	$K_{v1} = 5.45E+5$ kPa $K_{v4} = -879.84$ °C $K_{v5} = -265.99$ °C

4. Results and discussion

4.1. Comparison of the two methods

In the CSS-gas top injection method (Figure 1(c)), the interval steam injection and oil production perforation tend to be similar with the CSS conventional method. For the CSS-gas top injection process, the perforation is added the top side to inject the gas. In the study, the steam is injected for 25 days; furthermore, the well is soaked for 5 days and produced for 9 months. The durations of steam injection, soaking, and production periods are the same for both methods. The top of the perforated interval is 60 ft apart from the top reservoir to reduce heat loss due to the overburden and gravity override of steam. The interval gas injection perforation in the CSS-gas top injection method is about 15 ft from the top formation.

Figure 2(a) shows the comparison of oil rate production for the CSS conventional and CSS-gas top injection methods. As can be seen in Figure 2(a), in the first cycle, the peak of oil rate production is the same for both methods. For the CSS-gas top injection method, shortly after the first cycle started, the gas is injected to the well. Effects of the gas top injection will only influence the next cycles instead of the peak production rate of the first cycle. After the first production cycle is completed, the steam is injected again into the reservoir as a next cycle. The peak production rates of the further cycles are higher than that of the CSS conventional. It is because the remaining gas is still available in the top reservoir before the next cycle is started. It is comparable with the study done by Du et al. (2013). If the production perforation is opened, the gas pushes the oil and consequently the oil production rate will significantly improve. After the reservoir pressure is dropped, the gas is injected into the top side then production rate can be maintained again. This phenomenon is comparable to a documented research in steam and gas push study (Jiang et al., 2000; Zhao et al., 2005). The process is repeated until the end of the project life. Effect of this stage is that the cumulative oil production rate is better compared to the CSS conventional as displayed in Figure 2c.

On the other hand, Figure 2(b) displays the comparison CSOR for both methods. This clearly expresses that there is a really difference in the performance. The CSOR on the conventional CSS slightly increases proportionally with

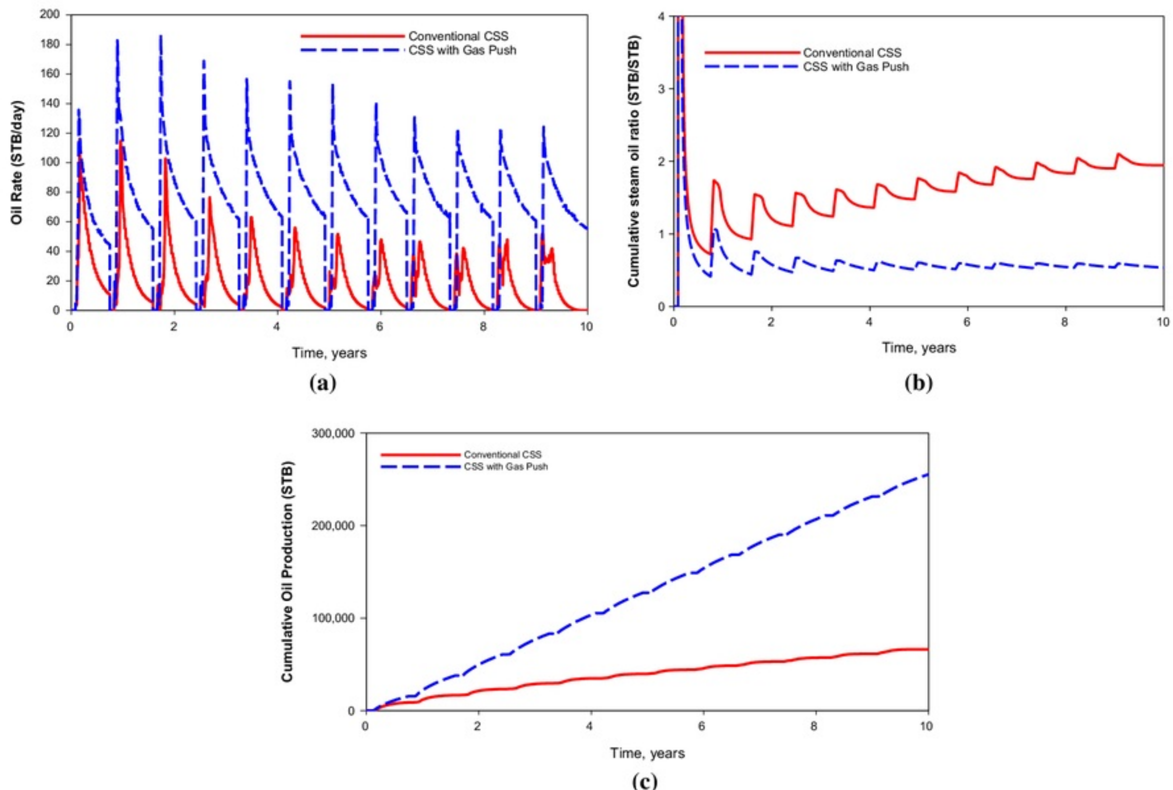

Figure 2. Comparison of conventional CSS and CSS-gas top injection. (a) Oil production rate vs. time, (b) CSOR vs. time, (c) Cumulative oil production vs. time.

increasing cycle while the CSOR in the CSS-gas top injection is still stagnant with increasing cycle. This indicated that the gas top injection has been successful to maintain the reservoir pressure, utilize the remaining heat on the reservoir, and push the crude oil to the production perforation.

Figure 3(a) and (b) show the comparison of oil flux in both methods. In the conventional CSS, as can be seen that the flux of oil spreads evenly to production perforation from out of boundary. It seems better but after several times, the production rate rapidly decreases because of the dropped reservoir pressure. On the other hand, in the CSS-gas top injection process, the flux of oil occurs on the top of oil zone because there is heat generated by steam, so the oil viscosity is reduced and it is easier to move. The advantage of gas top injection is that there is energy on the top of the oil zone as pressure maintenance, so the crude oil can move to the production perforation. In this process, the remaining heat still can be utilized to make oil production for longer time. After the remaining heat has been emptied, the reservoir condition will go back to the original condition and then, the oil production rate decreases. For reducing the oil viscosity again, the further cycles are employed.

Figure 3(c) shows the performance of gas flux in the CSS-gas top injection method. There are three phenomena that occur:. Firstly, the gas moves laterally in the reservoir; secondly, it dissolves to the oil phase; and thirdly, it directly moves to the production perforation. The first and second phenomena contribute to the pressure maintenance instead of the third phenomenon. So the optimum gas injection pressure is needed to maximize the first and second phenomena.

4.2. *Effect of extended time production*

Figure 4 shows the two different time cycles of CSS-top gas injection phenomenon. Here, the first cycle represents 10 months per cycle and the second one represents 20 months per cycle. The time production period of second cycle is combination of the first two cycles but the volume steam injection is about one-half of the first cycle. As can be seen on Figure 4(a), the trend of production rate from the both type of cycles is comparable. If the second

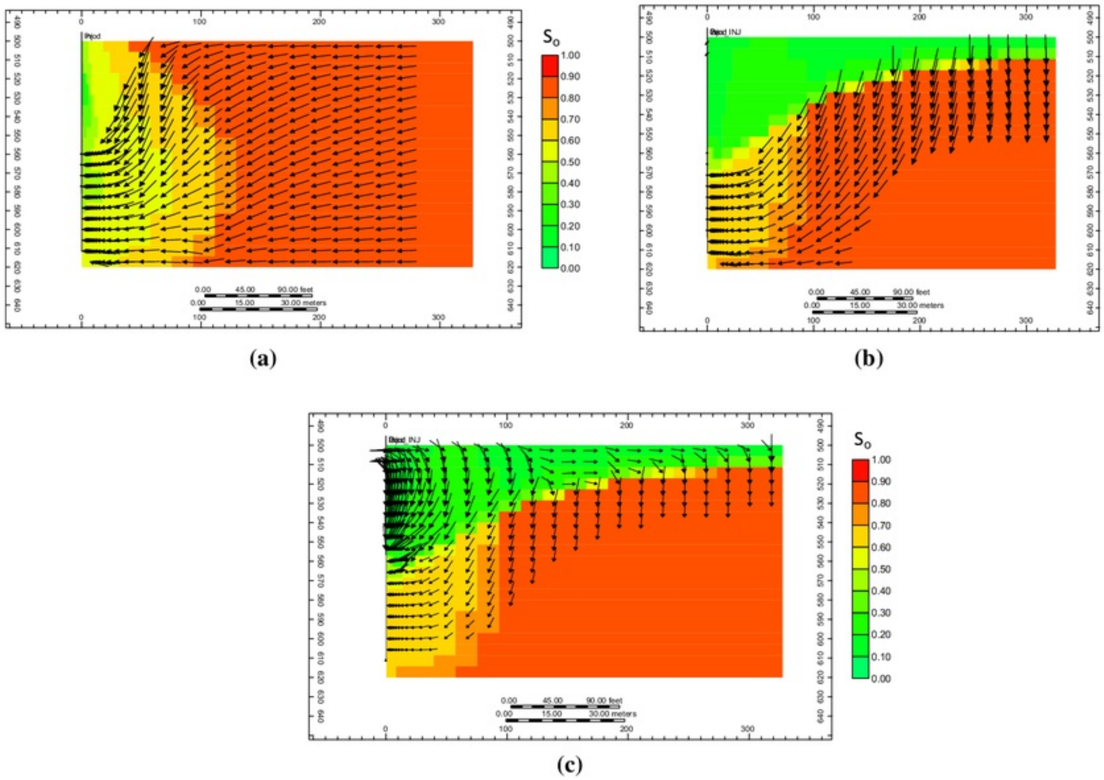

Figure 3. Comparison of flux of oil in conventional CSS and CSS-gas top injection; flux of gas in CSS-gas top injection. (a) Flux of oil in conventional CSS, (b) Flux of oil in CSS-gas top injection, (c) Flux of gas in CSS-gas top injection.

cycle has extended time production, the cumulative oil production is slightly lower than the first cycle which is about 25% as shown in Figure 4(b). In the previous part, it has been explained that after the reservoir pressure drops, the gas push injection is needed as pressure maintenance. Furthermore, the gas will stand up on the top side of reservoir. Obviously, if the cycle has extended time production, the volume of gas injection decreases.

There are two reasons leading to a slight decrease in the oil production rate in the second cycle compared to the first cycle. First, reduction of steam injection induces decrease of reservoir temperature. Second, decrease of the volume gas injection causes slight reduction of pressure maintenance effect. Consequently, the CSOR and volume gas injection reduce approximately 41 and 64%, respectively, as shown on Figure 4(b) and (c).

4.3. *Effect of volume gas injection*

As mentioned in previous part that the gas spreads in all directions. If the gas moves directly to the production perforation, the function of pressure maintenance will be useless. Figure 5(a) shows a comparison of cumulative gas injection in several gas injection pressure operations. For the volume gas injection of 490 MMSCF, the cumulative oil production is lower than that of the volume gas injection of 6500 MMSCF. In such case, it indicates that increasing the volume gas injection will have an effect on increasing volume oil production. But after that, the cumulative oil production will decrease after the cumulative gas injection of 11,600 MMSCF which indicates that much of the gas moves directly to production perforation.

There are two terms in CSS-gas top injection process. The first is energy efficiency, which is defined as the sum of enthalpy from steam injection utilized for getting the oil production per unit volume (cumulative energy oil ratio, cEOR). The second is gas top injection efficiency, the amount of gas that is injected to obtain the oil production per unit volume (cumulatives gas injection oil ratio, cgOR). As can be seen on Figure 5(b), to obtain 1 STB of oil in cumulative gas injection of 490 MMSCF, it will need 0.003 MMSCF of gas but energy is about 0.22 GJ/STB (Figure 5(c)). On the other hand, for the cumulative gas injection of 6500 MMSCF, it will need energy of approximately 0.16 GJ and the 1 STB will obtain 0.022 MMSCF.

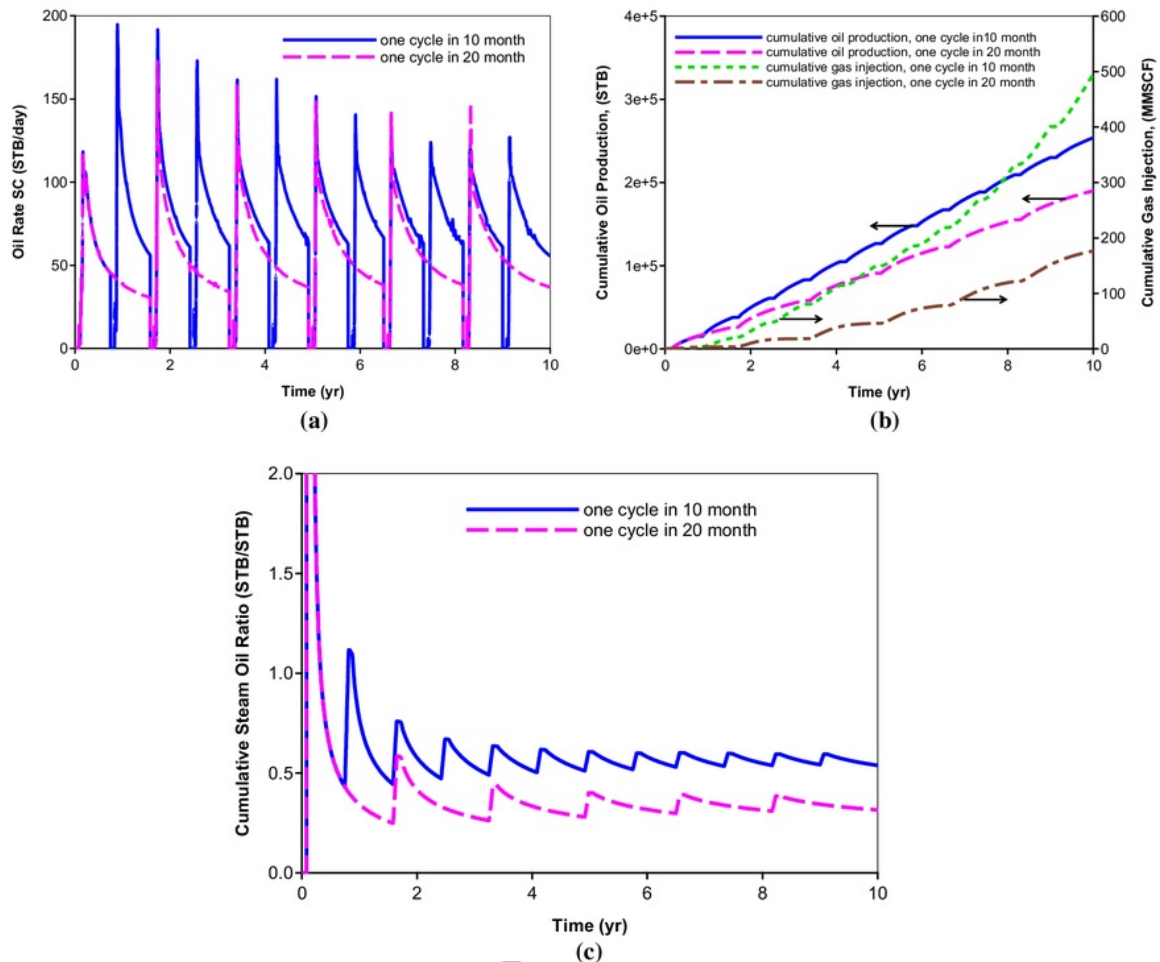

Figure 4. Comparison of two different time cycles in the production rate, cumulative oil production, cumulative gas injection and CSOR vs. time. (a) Comparison of two different time cycles in the oil production rate vs. time, (b) Comparison of two different time cycles in the oil production rate and the cumulative gas injection vs. time, (c) Comparison of two different time cycles in the CSOR vs. time.

If the cumulative gas injection increases, the cEOR will decrease and cgOR will increase.

4.4. Effect of reservoir thickness

Figure 6 shows the relationship between reservoir thickness, cumulative oil production, and CSOR after 10 years of production life. In both of the CSS processes, the CSOR increased with the reduction of reservoir thickness. In the conventional CSS case, increasing reservoir thickness slightly affects the cumulative oil production while the CSS-gas top injection, the thickness rapidly affects the cumulative oil production. It seems that for both CSOR methods, the increasing thickness will decrease CSOR. The effectiveness of steam also decreases because the heat easily loses to the overburden and the underburden.

In thin reservoirs, the perforations of injection and production sections are close to each other. Hence, the effect of pressure maintenance in the cumulative oil production is not significant compared to that in the thick reservoir. It causes the injected gas to move to the production perforation directly due to the very close distance between injection and production perforation. In contrast, if the reservoir thickness is higher, the gas injection spreads to the all directions and dissolves to the reservoir fluid. In such condition, the pressure can be maintained for longer time. Furthermore, when the thickness is lower than 10 ft, the CSOR of the CSS-gas top injection method is higher than CSS conventional. In addition, when the thickness is 20 ft, the cumulative oil production of both methods is almost similar. So the reservoir thickness of the CSS-gas top injection method must be more than 20 ft to get the favorable process.

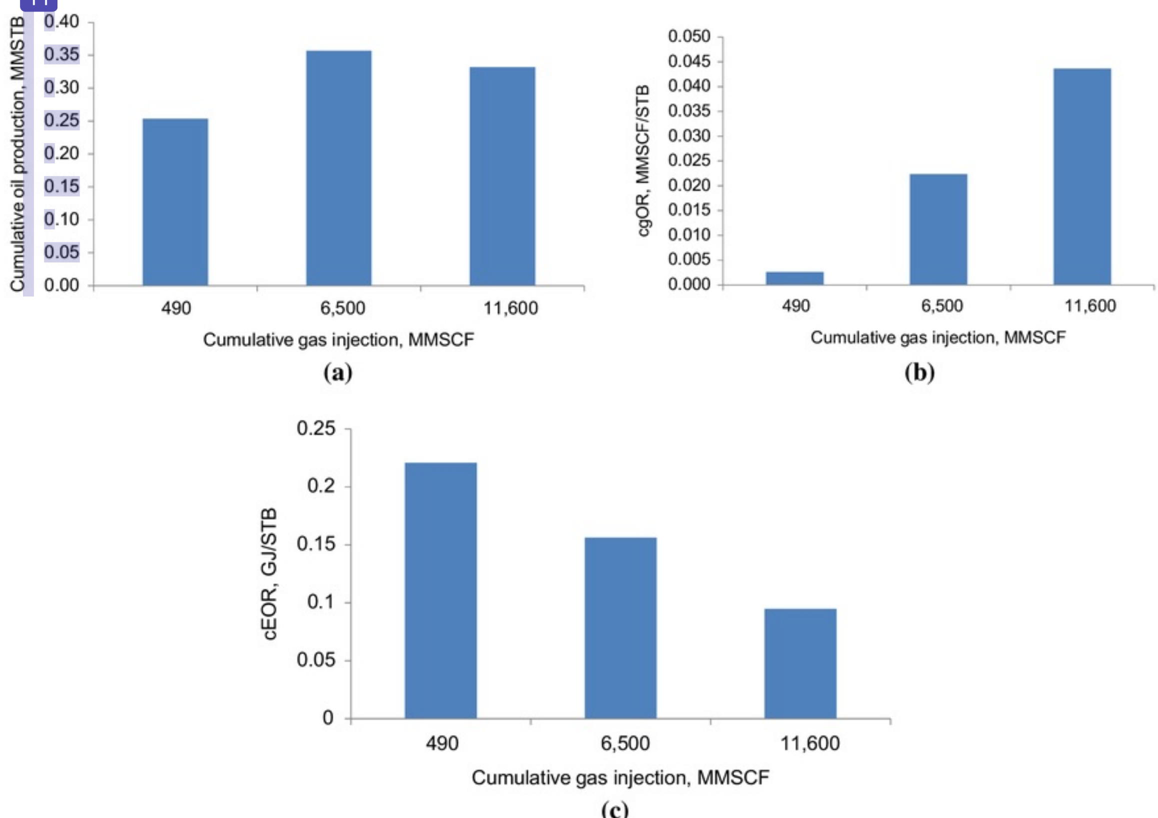

Figure 5. Effect of cumulative gas injection on cumulative oil production, cgOR and cEOR in CSS-gas top injection. (a) Cumulative gas injection vs. cumulative oil production, (b) Cumulative gas injection vs. cgOR, (c) Cumulative gas Injection vs. cumulative energy oil ratio (cEOR).

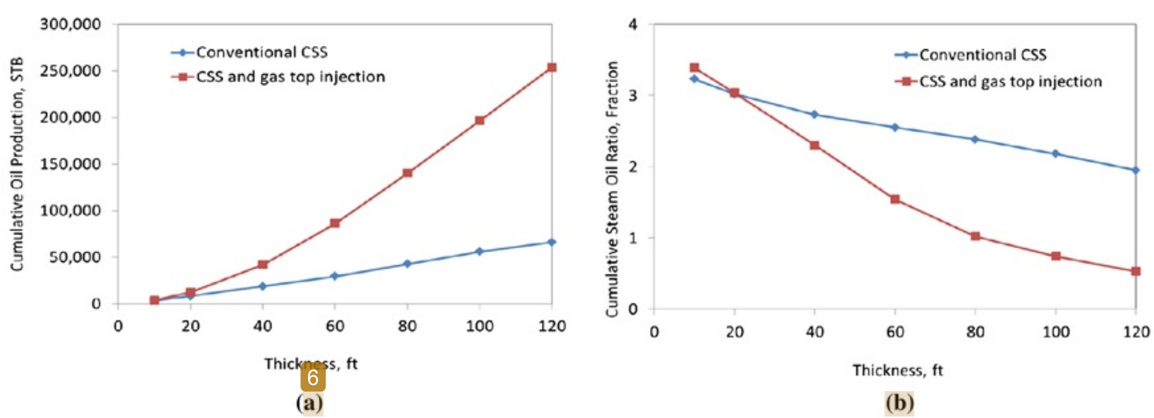

Figure 6. The comparison of cumulative oil production and cSOR on the both of methods. (a) Cumulative oil Production vs. thickness, (b) CSOR vs. thickness.

5. Conclusions

This research expresses that the combination of CSS and gas top injection can be favorable compared to CSS conventional. The functions of gas top injection are to utilize the remaining heat, to maintain the reservoir pressure, and to push the reservoir fluid to the production perforation. Because the gas is very mobile, the high volume gas injection will shorten breakthrough time. On the other hand, the thin reservoir will reduce the effectiveness of gas top injection method because the gas moves directly to the production perforation. The reservoir simulation results show that the volume gas injection could be approximately 6500 MMSCF and profitable. If the cycle time production is extended, the steam effectiveness increases. Here, the CSOR and cumulative production are reduced by approximately 41 and 25%, respectively. Furthermore, the thickness must be more than 20 ft to get the favorable process. The base case scenario of this research is that the cumulative production will increase approximately by 3.5 times and the CSOR will decrease approximately by 60% compared to the CSS conventional.

Nomenclature

CSS	cyclic steam stimulation
SCF	standard cubic feet
STB	stock tank barrel
SAGD	steam-assisted gravity drainage
CSOR	cumulative steam oil ratio
SOR	steam oil ratio
cEOR	cumulative energy oil ratio
cgOR	cumulative gas oil ratio
SAGP	steam and gas push
BHP	bottom hole pressure
OOIP	original oil in place

SI metric conversion factors

bbl × 0.159	m^3
cP × 0.001	Pa.s
ft x 3.048	m
(°F − 32)/1.8	°C
psi x 6.8947	kPa

Disclosure statement

No potential conflict of interest was reported by the author.

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