Hindawi
Geofluids
Volume 2022, Article ID 7146119, 19 pages
https://doi.org/10.1155/2022/7146119

Research Article

Experimental and Numerical Investigation on Infilled Vertical Well LASER-Assisted SAGD

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Received 20 April 2022; Accepted 21 July 2022; Published 18 August 2022

Academic Editor: Zhiyuan Wang

In the SAGD process with dual horizontal wells in heterogeneous reservoirs, the injection pressure of steam huff-n-puff by infilled interwell vertical wells is too high, and the heat communication between SAGD wellpairs and infilled wells is too long, which leads to a series of problems. The solvent-assisted vertical well stimulation (LASER) technology is proposed to solve the problems above. The solvent formula was optimized, and its key mechanism was studied by viscosity reduction experiments, multicomponent phase behavior experiments at high temperature and high pressure, and scaled two-dimensional physical experiments. The experimental results show that when adding 10% 2# or 3# solvent oil, the viscosity reduction of crude oil can reach 96.65% and 96.73%, respectively. The HTHP visualized phase behavior experiment results show that the mixture of low flash point solvent oil 2# with high flash point solvent oil 3# (volumetric ratio 3 : 2) has excellent high temperature oil solubility stability and is similar to water vapor phase behavior, so it is determined as the ideal formula. The scaled two-dimensional physical experiment results show that the solvent-assisted vertical well huff-n-puff has the key mechanism of reducing injection pressure and porous flow resistance, expanding the sweep region of injected fluid and accelerating thermal communication. The cycle of huff-n-puff was reduced from 6 to 3, which greatly shortened the thermal communication time. From the scaled physical experiments, the oil rate and the oil recovery of SAGD were improved by 19.86% and 6.3%, respectively. Field-scale numerical simulation was performed, and the production performance compared with SAGD and conventional infilled CSS-SAGD was investigated, which shows that by adding solvent into steam stimulation, 6 cycles were reduced, and the incremental oil recovery factor was 27.3% and 13.2%, respectively. The performance of accelerating thermal communication and production improvement by LASER has been validated by 4 SAGD wellpairs in field practice, and its long-term prediction result shows significant potential in similar heterogeneous SAGD reservoirs.

1. Introduction

Since the massive expansion of commercialized SAGD (steam-assisted gravity drainage) projects in Canada and China in 2008 [1], most deposits with less heterogeneities have been developed, leaving marginal deposits with poor reservoir properties and strong heterogeneity [2, 3]. As the steam chamber shape is sensitive to the reservoir properties [4, 5], poor sedimentation conditions always result in uneven steam chamber conformance and low oil recovery factor [6–8]. In order to produce the bypassed deposits of existing SAGD wellpair, infilled wells are suggested to deploy in the interwellpair region [9–12]. Owing to the advantages of flexible operation regulation and better suitability in interbedded reservoirs, multiple vertical wells are the first choice of infilled drilling [13], which has been successfully implemented in several SAGD projects in Canada and China [14]. Infilled horizontal well or wedge well is also an alternative [15], while it is more suitable for wellpairs with less geologic heterogeneity as the shale barriers are likely to reduce the drill encounter rate of infilled horizontal wells.

For vertical infilled wells, several cycles of steam huff-n-puff is necessary to establish the thermal and fluid communication between vertical wells and existing SAGD steam chamber [16], while this process should be carefully designed, as the steam huff-n-puss is a large-scale pressure fluctuation process with normally more than 7 MPa of pressure differential before and after steam injection. As SAGD operation is a process with semibalanced pressure, to avoid fracturing the steam chamber, it is required to reduce the cyclic steam injection to reduce the maximal injection pressure, which leads to more cycles and longer time for thermal communication [17].

As the SAGD steam chamber constantly develops with time, later thermal communication establishment means shorter combined process of vertical-SAGD operation and less effect of vertical wells on the SAGD performance improvement and recovery factor. Another challenge for vertical-SAGD operation is that the oil viscosity at the steam temperature is still 30-50 mPa.s, which is almost twice that in SAGD projects in Canada (10-20 mPa.s). Higher oil viscosity poses a threat to the swept volume of steam due to higher flow resistance and higher risks of steam channeling. As has been validated by field performance [18, 19], the addition of solvent into steam is an effective method to further reduce the oil viscosity and enhance the injected fluid flow mobility, which has been used in ES-SAGD and steam huff-n-puff process [20], in which the liquid addition to steam for enhancing recovery, in other words, the addition of solvent in steam huff-n-puff process is called LASER in petroleum industry [21]. Although the solvent has been used in SAGD preheating phase [22], its application in infilled vertical well-assisted SAGD has not been studied. Its mechanism and feasibility are also not fully understood.

How to reduce the steam injection pressure and the cycles needed to establish the thermal communication is the biggest challenge for vertical-SAGD operation. The solvent-assisted steam huff-n-puff (LASER) is proposed in this study. Experimental and numerical approaches have been combined to optimize the proper solvent formula and investigate the feasibility and mechanisms, which directly attributes to the successful implementation of field pilot tests.

2. Solvent Formula Optimization Experiments

Due to the high cost of liquid solvent such as n-hexane and n-heptane, during the preheating process between infilled vertical wells and SAGD steam chamber, the added solvent should be characterized of "low proportion, high oil viscosity reduction ratio, and less vaporization." In other words, it is required to use a small amount of solvent to take maximum effect. To this end, focused on viscosity reduction effect and high temperature phase behavior, different solvent systems were investigated to acquire the optimal formula.

2.1. Evaluation Experiment of Viscosity Reduction Effect of Solvent. Using a HAAKE MARS III rheometer with a HTHP closed test system and based on industry standard (SY/T 7549-2000: determination of oil viscosity-rotational viscometer method), the viscosity reduction effects of different solvent systems (benzene, toluene, xylene, trimethylbenzene, diesel, gasoline, 1# solvent oil, naphtha, 2# solvent oil, and 3# solvent oil) on Fengcheng super heavy oil were tested.

According to the Arrhenius' viscosity calculation model for hydrocarbon solvent and crude oil mixture, light hydrocarbon solvent with excellent performance can reduce the viscosity of crude oil approximately exponentially, while different solvent has quite different performance due to its compatibility with crude oil and molecular diffusion behaviors. The experimental results show that different solvents have obvious viscosity reduction effect on heavy oil, and the viscosity reduction rate increases with the amount of solvent. Among them, the viscosity reduction rates of 2# solvent oil and 3# solvent oil (92.65% and 96.73%, respectively) were significantly higher than those of other solvents at the same dosage of 10% (Figure 1). According to the viscosity reduction rate, 1# solvent oil with low flash point (37.5°C), 2# solvent oil with flash point (65.6°C), and 3# solvent oil with high flash point (112.3°C) were selected as preliminary solvent types.

The mixed viscosity of 1# solvent oil, 2# solvent oil, and 3# solvent oil, which have the best viscosity reduction effect, was measured in different proportions with crude oil. The regression equation shows that the viscosity of mixed oil has a semilogarithmic linear relationship with solvent concentration (Figure 2).

It can be seen from the visualized oil dissolution process that the light hydrocarbon solvent can quickly dissolve and reduce the viscosity of super heavy oil by molecular diffusion without external pressure difference. When the volume ratio of super heavy oil and 3# light hydrocarbon solvent oil is 1 : 4, the complete dissolution of super heavy oil can be achieved in only 3 minutes (Figure 3).

2.2. Solvent Phase State Experiment at High Temperature. In the huff-n-puff process of solvent with steam injection, the phase behavior of solvent and steam directly affects the oil viscosity reduction efficiency and solvent action time at steam front. In view of the great difference in volatilization of solvents with different flash points and boiling points at high temperature, in the process of steam huff-n-puff, solvents with low flash points are still in the gas phase after huff-n-puff and soaking. In the process of production after soaking, the solvent is easy to be produced and cannot play the role, while solvents with high flash points have poorer performance in oil viscosity reduction. Therefore, although low flash point solvent has excellent viscosity reduction property, the comprehensive benefit in actual reservoir is not economical, and it needs to be combined with high temperature phase state to comprehensively judge. A mercury-free ST-PVT instrument with high temperature and high pressure was used to test the phase characteristics of the composite system at high temperature and high pressure under the coexistence of different solvent-water vapor systems.

According to the phase state experimental results, in the system with low flash point solvent-water coexistence, when the temperature increases or the pressure decreases, the solvent gasification happens preferentially, and a small number of tiny bubbles appear on the top of the visualized PVT cylinder (Figures 4(a) and 4(b)). In the system with high flash point solvent and water coexistence, when the temperature

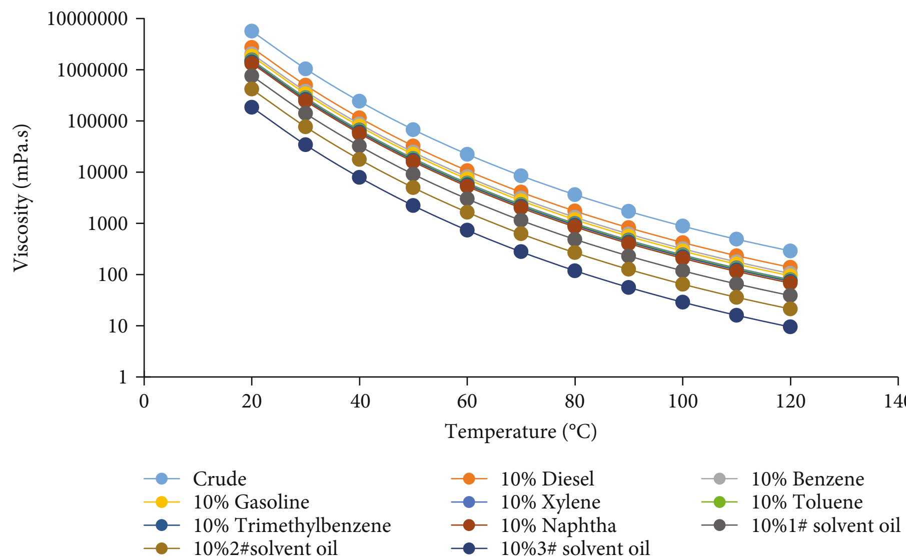


Figure 1: Experiment of dissolving asphalt with different solvents (50°C).

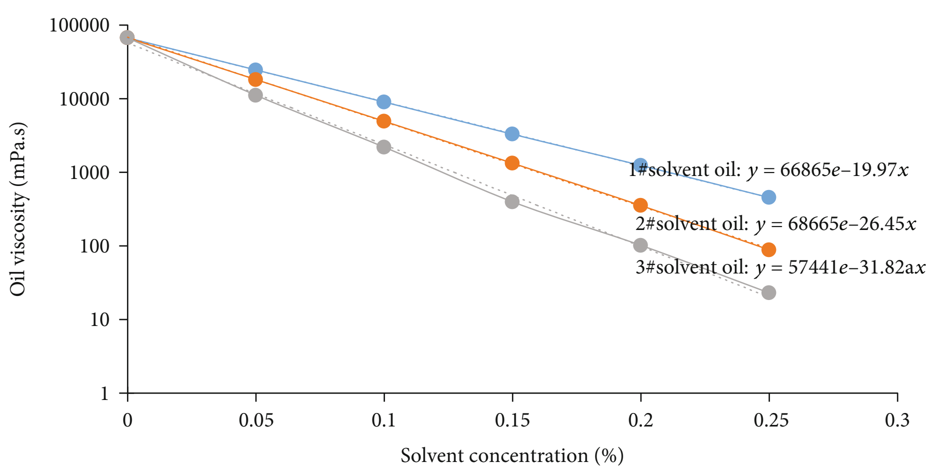
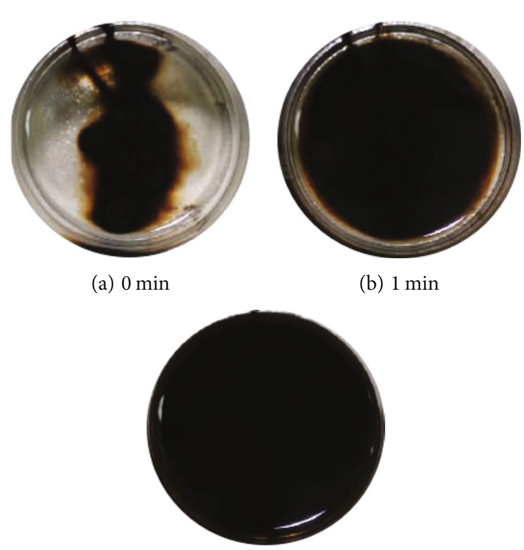


Figure 2: Oil viscosity of different solvent proportion with oil (50°C).



(a) 0 min (b) 1 min

(c) 3 min

Figure 3: Visualization of oil dissolution process with light hydrocarbon solvent (2# solvent oil).

(a) 1#

(b) 2#

(c) 3#

Figure 4: High temperature visualization of phase states of different solvent oil-water vapor systems.

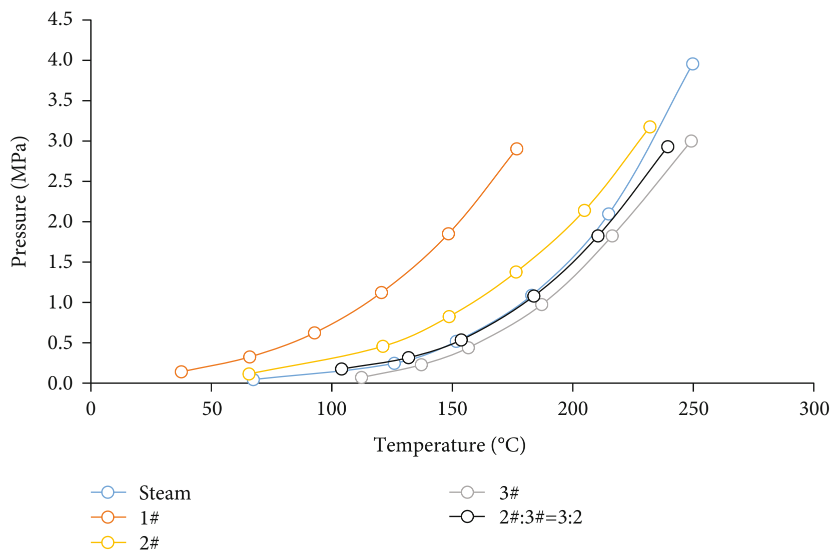


Figure 5: Vapor pressure curves of different solvent oil-water system.

rises or the pressure decreases, water is preferentially vaporized, and steam bubbles aggregated at the top of the PVT cylinder. Since the volume ratio of solvent to water is 1 : 9, water is much more than solvent, and the volume of steam from water (bubbles in the PVT cylinder) is also much more than that of solvent vapor (Figure 4(c)).

According to different solvent-water saturated vapor pressure curves (Figure 5), the saturated vapor pressure curves of different solvent systems differ greatly. The saturated vapor pressure curves of low flash point 1# solvent oil and 2# solvent oil are far from that of water vapor, and they are still gaseous at 100°C. The temperature range at the end of the 3-5 cycles is usually 80-130°C, and the two solvents above in this temperature range are still continuously separated from the crude oil by gasification, thus greatly reducing solvent efficiency. The saturated vapor pressure curve of 3# solvent oil with high flash point is located on the right side of the water vapor curve, indicating that it is still liquid in water vapor state, which plays an important role in long-term oil dissolution and viscosity reduction. And the test by blending the 2# with the 3# solvent oil (volume ratio 3 : 2) found that the saturated vapor pressure curve of the hybrid system at above 210°C is in the right side of the curve of water vapor, and under 210°C, it is almost overlapping with steam curve, indicating that this solvent system has the similar phase state characteristics with water vapor in the process of temperature cooling during cyclic production period, which can play a maximum role.

Synthetically considering the oil viscosity reduction and HTHP phase state characteristics, the optimal solvent formula was determined to be the mixture of 2# and 3# solvent oil (volume ratio 3 : 2).

3. 2-D Scaled Physical Experiments

In order to investigate the mechanisms of vertical LASER-assisted SAGD in aspects of porous flow resistance reduction by solvent dissolution and oil viscosity reduction, expand the injected fluid effect radius during steam huff-n-puff, and accelerate thermal communication, the 2-D scaled physical

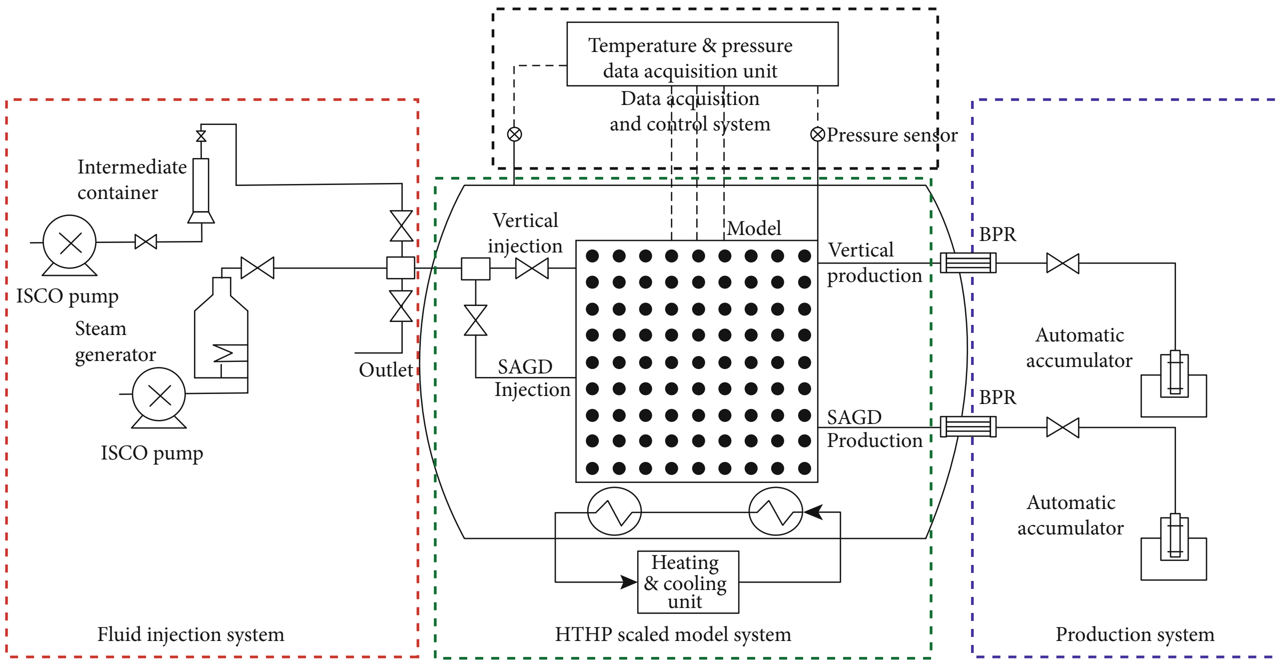


Figure 6: Flow chart of 2-D HTHP scaled physical experiment.

experiments were designed, which include conventional vertical CSS and vertical LASER-assisted SAGD. The experimental phenomena including reservoir temperature field evolution characteristics, thermal front advancement characteristics, and thermal communication shapes were analyzed.

3.1. Experimental Materials. The test oil was obtained from a typical SAGD reservoir in Z block, Xinjiang oilfield. The formation water was prepared based on the formation water salinity and composition. The rock particle size was analyzed according to the core data, which guided the sand packing of the model.

3.2. Experimental Setup. As shown in Figure 6, the 2-D scaled experimental system is mainly comprised of 4 parts: (1) fluid injection system consists of a steam generator to inject steam at predetermined pressure and temperature, an ISCO pump, and intermediate containers, which are used to saturate formation water and oil. (2) HTHP scaled model system includes a stainless-steel model with the size of 5 cm∗40 cm∗20 cm (length∗width∗height). 112 thermal couples in total were deployed inside with 14∗8 points in width and height direction, respectively. 1 horizontal wellpair and a vertical well were placed in the model. 9 pressure gauges were evenly installed in the model to monitor the pressure changes. (3) Data acquisition and control system include the temperature and pressure data acquisition modules and the software to interpolate the real-time temperature field. (4) Production system includes the BPR valve, fluid-gathered bottles, a centrifuge to separate the oil and water, and the balance to meter the produced fluid. The model system and the well placement are shown in Figure 7, in which the wellpair is located at the right side of the model, to simulate the half-wellpair, and the vertical well is positioned in

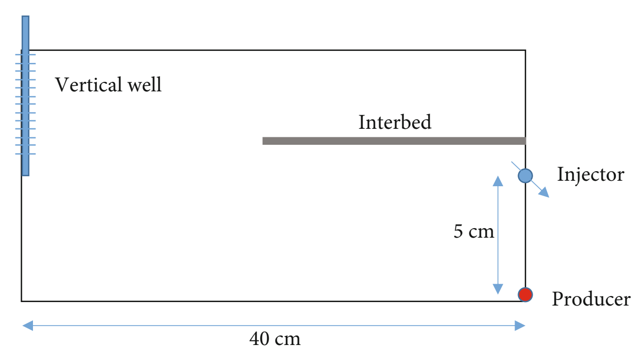


Figure 7: Layout map of vertical and SAGD wells.

the top of the left side, with the perforation section covers the upper half of the model. An interbed is located above the injector, which acts as a barrier to impede the steam chamber uprising and growth.

3.3. Experimental Schemes. In order to compare the effects of solvent addition on temperature field evolution, thermal communication time, and the following infilled vertical-SAGD production performance, two cases of 2-D scaled physical experiment were designed: case 1 is infilled vertical well steam huff-n-puff assisted SAGD, and the case 2 is infilled vertical well LASER-assisted SAGD. In case 2, the proportion of solvent with steam is 1 : 9. Based on the similarity criteria of scaled physical experiments and the targeted reservoir parameters [23], the experimental parameters were designed as follows (Table 1).

3.4. Experimental Procedures. The experimental procedures include the following 7 steps:

(1) *Well Deployment.* The SAGD wellpair and the infilled vertical well are placed according to the field

Table 1: Design results of the reservoir and the 2-D physical model.

Items	Reservoir	Lab
Geometry size (width*height)/m	70*18	0.40*0.20
SAGD wellspacing/m	5	0.1
Porosity/%	32	35
Permeability/10^{-3} μm^2	1300	88002
Initial oil saturation/%	76	87
Oil viscosity@50C/mPa.s	11232	11232
Oil density@50C/kg.m^{-3}	1008	1008
m (function of oil viscosity, steam temperature T, and reservoir T_R)	3.4	3.4
Geometry similarity coefficient: R	0.143	0.143
Property similarity coefficient: B_3	0.18	0.18
Time similarity coefficient: t_D	$3.9*10^{-5}$t	0.26t
Velocity similarity coefficient: q_s/m^{-3}.d^{-1} (cold water equivalent)	0.023	0.02

practice, in which the SAGD wellpair is located 1/3 to the right side of the model and the infilled vertical well is located 1/5 to the left side of the model

(2) *Sand Packing*. The model is prepared by testing the airtightness, the packing of the sand with quartz sand (15-40 mesh), and the vacuum pumping

(3) *Brine Saturation*. The formation water is prepared according to the salinity of formation water, and the model is aged for 48 hours after water injection

(4) *Oil Saturation*. The model is heated to 80°C, and the experimental crude oil is heated to 90°C. The model is saturated with oil at an injection rate of 5-30 mL/min, and the total injection volume is calculated according to the pump data. The oil saturation process continues until one hour after the water saturation from the outlet reduces close to 0%, and the model is aged again for 48 hours to establish the initial oil-water-rock interfacial relationship

(5) *SAGD Preheating and Production*. Steam is circulated in both injector and producer for 30 minutes to establish the thermal communication and then converting to SAGD production mode

(6) *Infilled Vertical Well Huff-n-Puff-Assisted SAGD*. SAGD wellpair continues to injection and production, while infilled vertical well begins to establish the thermal communication by steam huff-n-puff. The injection fluid is pure steam and steam with solvent for case 1 and case 2, respectively

(7) The real-time model temperature is monitored by thermal couples through the temperature data acquisition module and software, and the temperature field is mapped accordingly

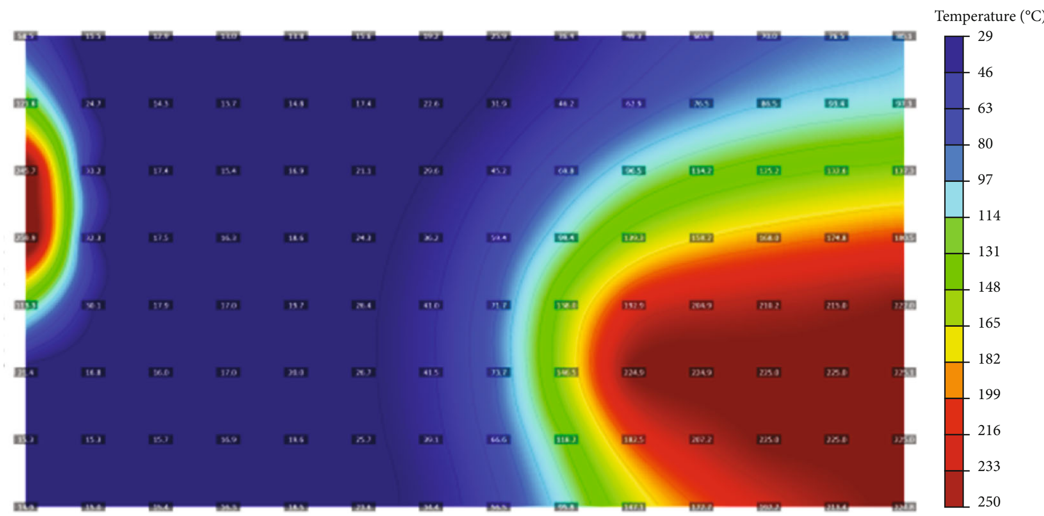
3.5. Results and Discussion

3.5.1. Temperature Field Evolution. In comparison with the temperature fields of each cycle, it is shown that the temperature field expands slowly for case 1, which needs 6 cycles for the vertical well to establish thermal communication with the SAGD wellpair. While in case 2, the preliminary thermal communication is realized by 3 cycles with the addition of 10% solvent, indicating that the addition of solvent can effectively speed up the thermal communication by approximately twice on the basis of conventional huff-n-puff.

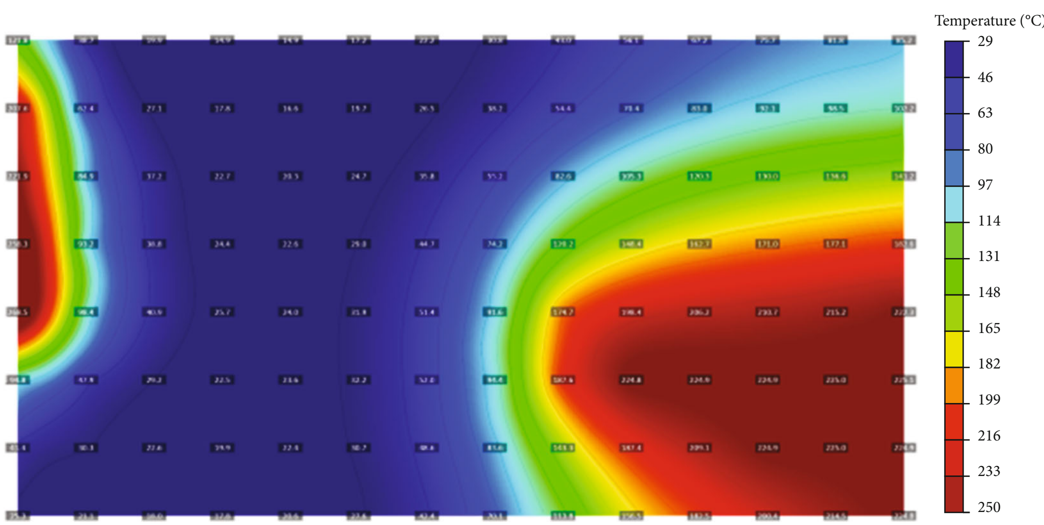
It is noted in Figures 8(a)–8(d) that it is difficult for the steam chamber of conventional CSS to expand rapidly due to the high flow resistance by high oil viscosity. By comparison, Figures 9(a)–9(c) show a different phenomenon. Due to the further reduction of oil viscosity by solvent dissolution, the steam chamber expands more quickly in LASER process and less cycles needed to establish thermal communication with SAGD steam chamber.

Furthermore, operational parameters also impact the thermal communication performance. As shown in Figure 10(a), in production period of conventional CSS, the bottomhole pressure of vertical well directly impacts the steam flow path from the exiting SAGD steam chamber. As there is a pressure differential of 0.57 MPa between the vertical well and the steam chamber, the steam is attracted towards the vertical well, and the steam fingering is evident. This is detrimental to the steam flooding phase. As shown in Figure 10(b), the steam from the vertical well flows directly through the steam channel and limits the steam sweeping area (Figures 10(c) and 10(d)), which consequently results in a lower oil recovery factor.

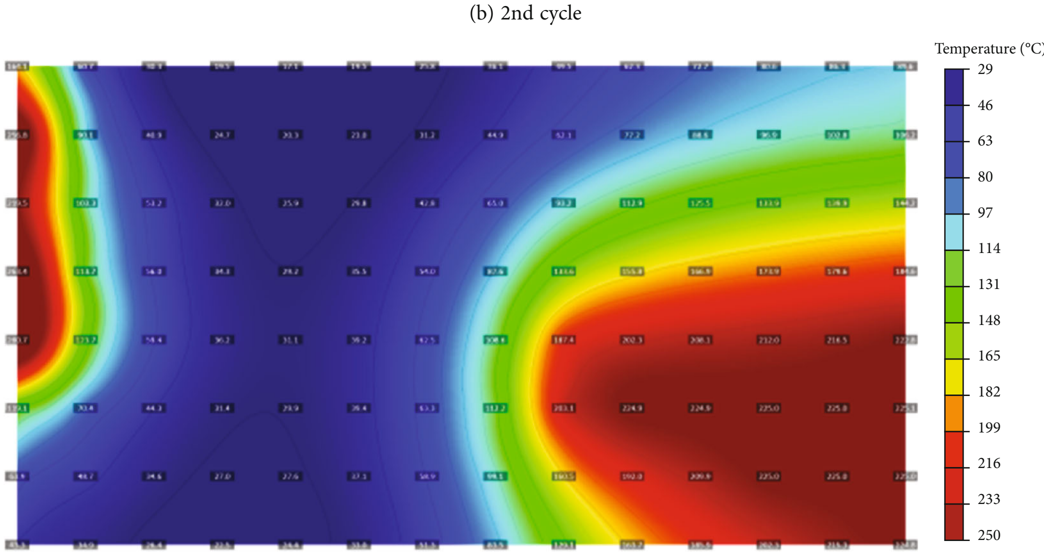
Under the rational control of operation pressure and steam injection rate, the case 2 has a quite different temperature conformance in steam flooding phase. As shown in Figure 11, the steam from vertical well flows steadily towards the SAGD producer, and the steam front is quite stable, without apparent steam fingering phenomenon. This is due to larger mobilized region by solvent addition during preheating phase, and operational strategies involving both the vertical well and the SAGD wellpair. From the comparison of temperature profiles, it is noted that the thermal communication performance has a long-term impact on the



(a) 1st cycle

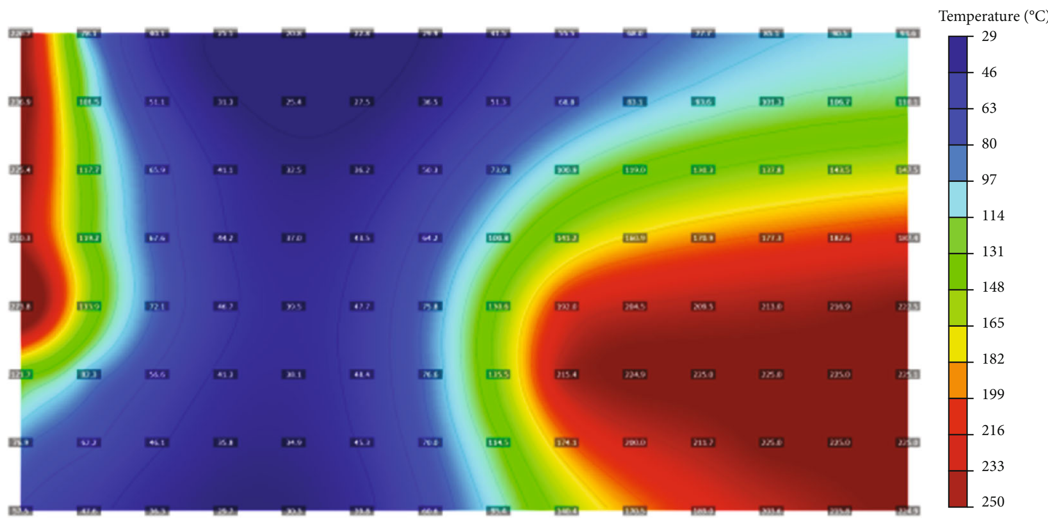


(b) 2nd cycle

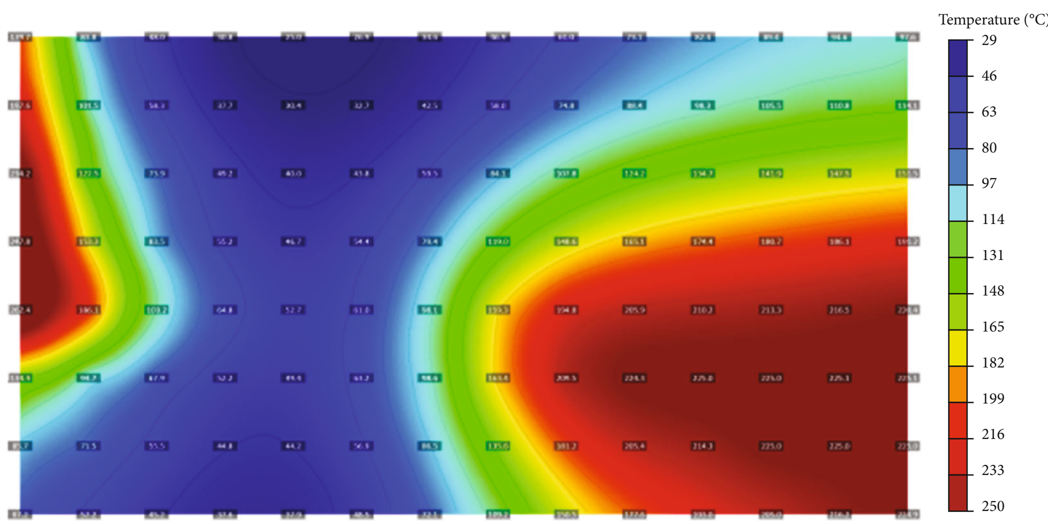


(c) 3rd cycle

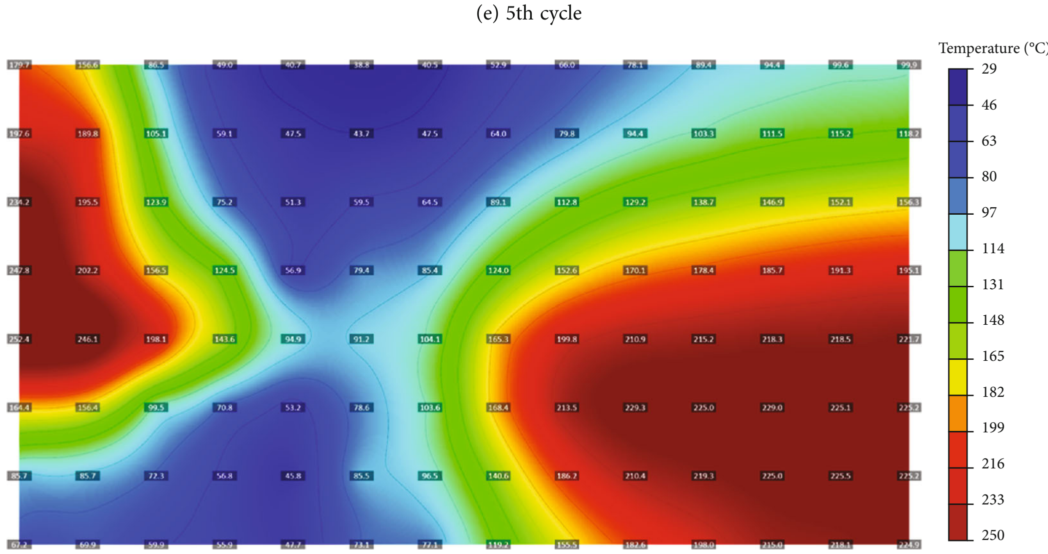
Figure 8: Continued.



(d) 4th cycle

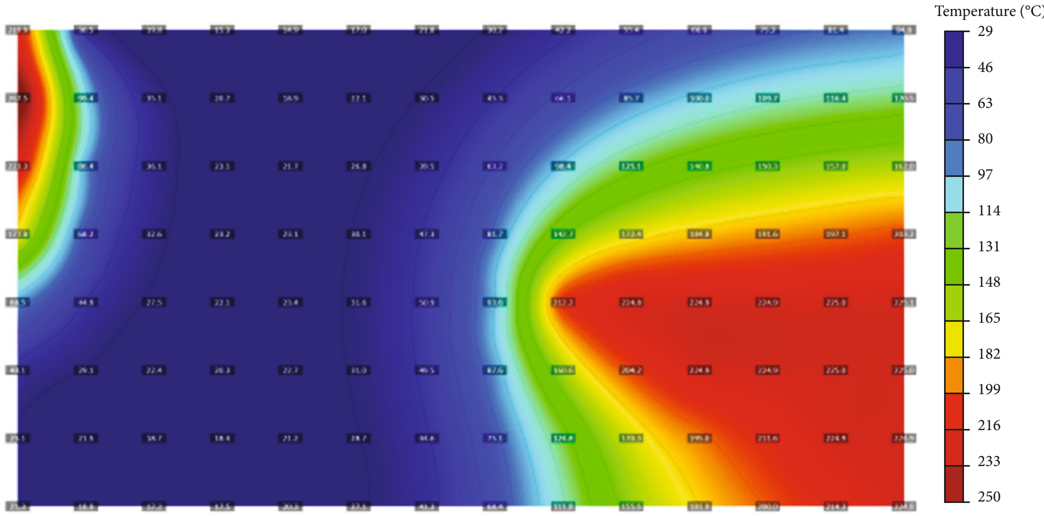


(e) 5th cycle

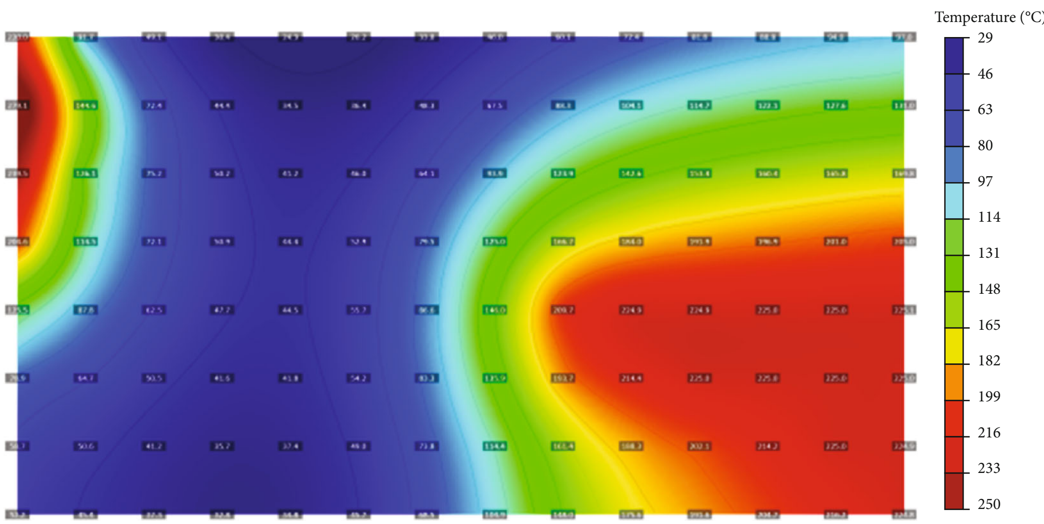


(f) 6th cycle

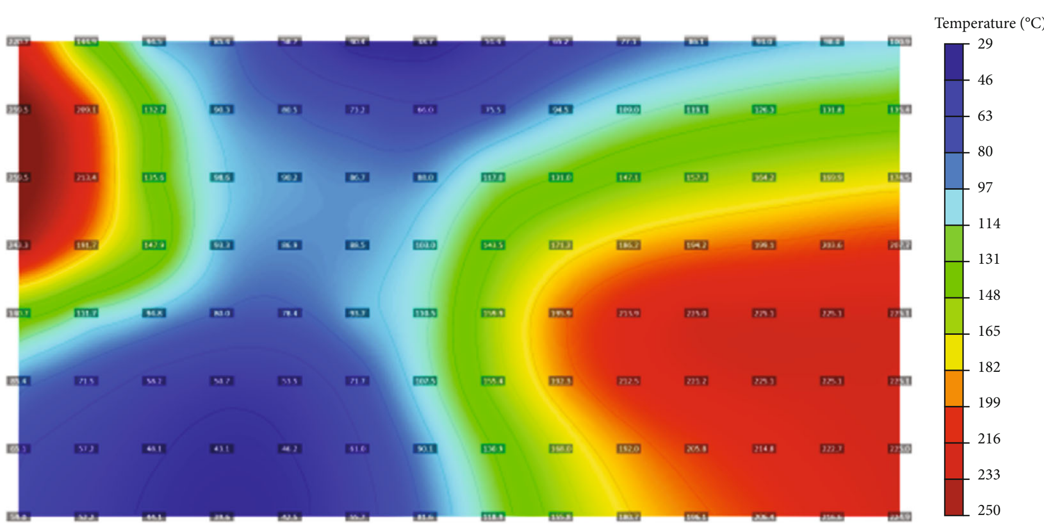
Figure 8: Temperature distribution of different cycles of infilled conventional CSS-SAGD.



(a) 1st cycle

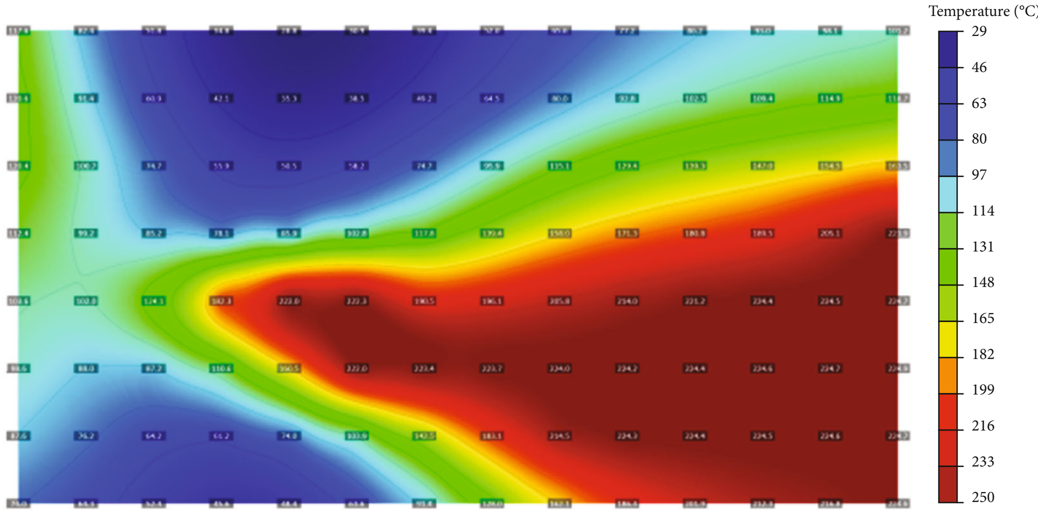


(b) 2nd cycle

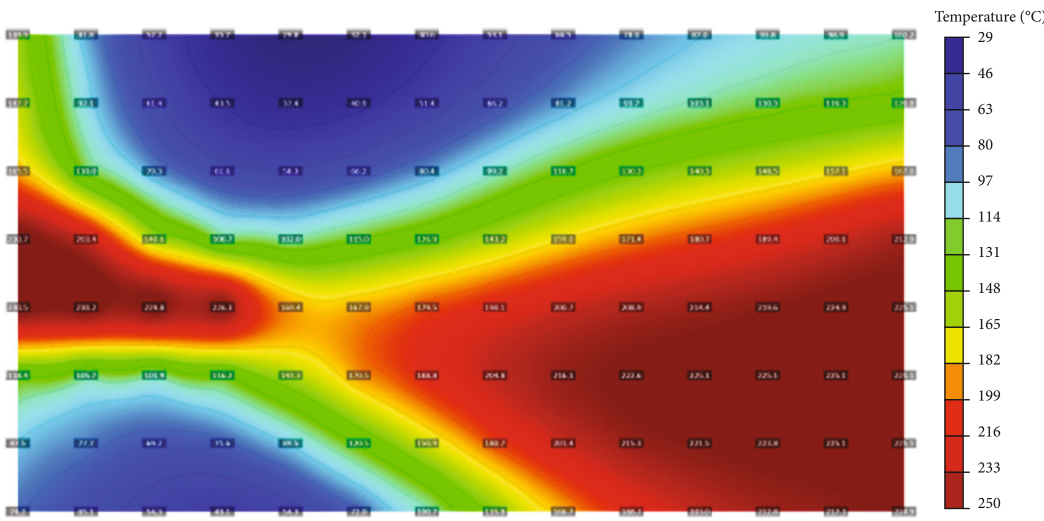


(c) 3rd cycle

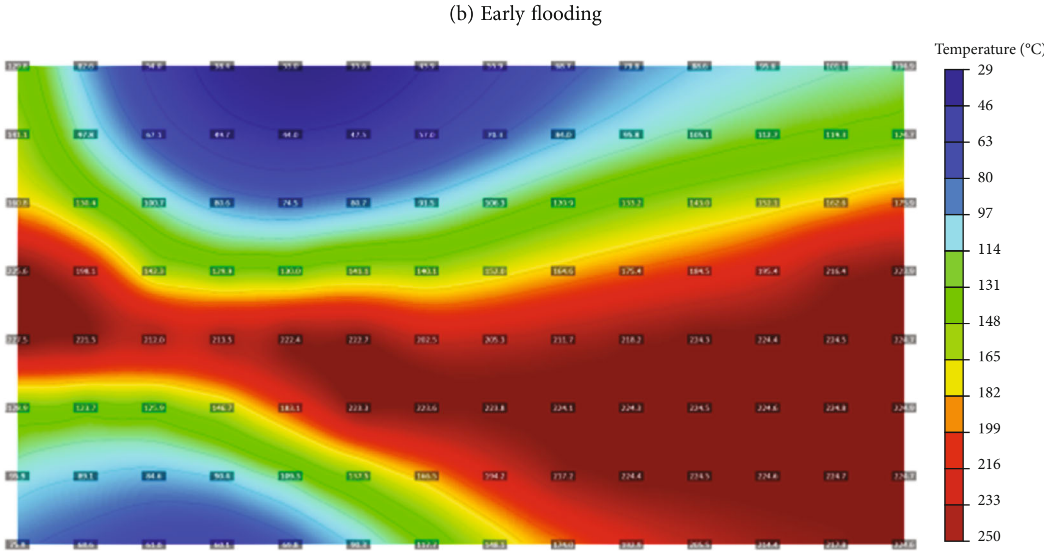
Figure 9: Temperature distribution of different cycles of infilled LASER-SAGD.



(a) Preheating end

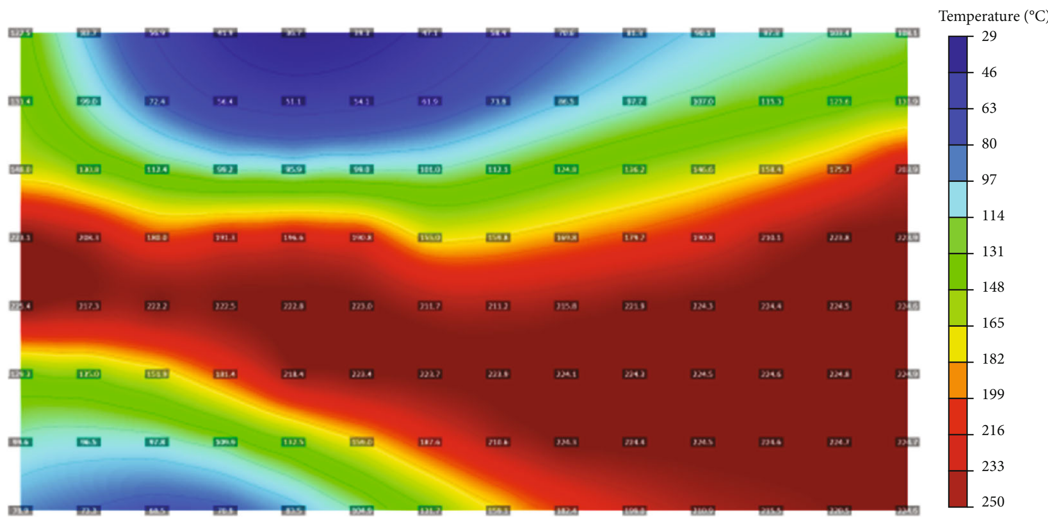


(b) Early flooding



(c) Midflooding

Figure 10: Continued.



(d) Flooding end

FIGURE 10: Temperature distribution of vertical-assisted SAGD preheated by conventional CSS.

flooding performance, which can be achieved by addition of small proportion of solvent.

3.5.2. Production Performance. Like the temperature profile has validated a larger steam swept area, the production performance by infilled vertical-LASER startup is also significantly improved. As shown in Figure 12, the oil rate ramp-up speed of conventional infilled CSS-SAGD is slower than infilled LASER-SAGD, and the plateau oil rate of conventional infilled CSS-SAGD is also lower than infilled LASER-SAGD. By adding 10% solvent into steam, only 3 cycles are needed to reach the thermal communication, and the plateau oil rate can reach 242.6 ml/hour, which is enhanced by 19.86%. Furthermore, in comparison with conventional infilled CSS-SAGD, the ramp-up time to reach peak oil production is 2.96 hours, which is shorten by 40.2%. In addition, as the swept region of steam increases by solvent addition, more oil reserve can be effectively recovered, which leads to a final recovery factor of 59.6%. On the contrary, the oil recovery factor for conventional infilled CSS-SAGD is only 53.3%, which is 6.3% lower than the solvent addition case.

4. Numerical Simulation

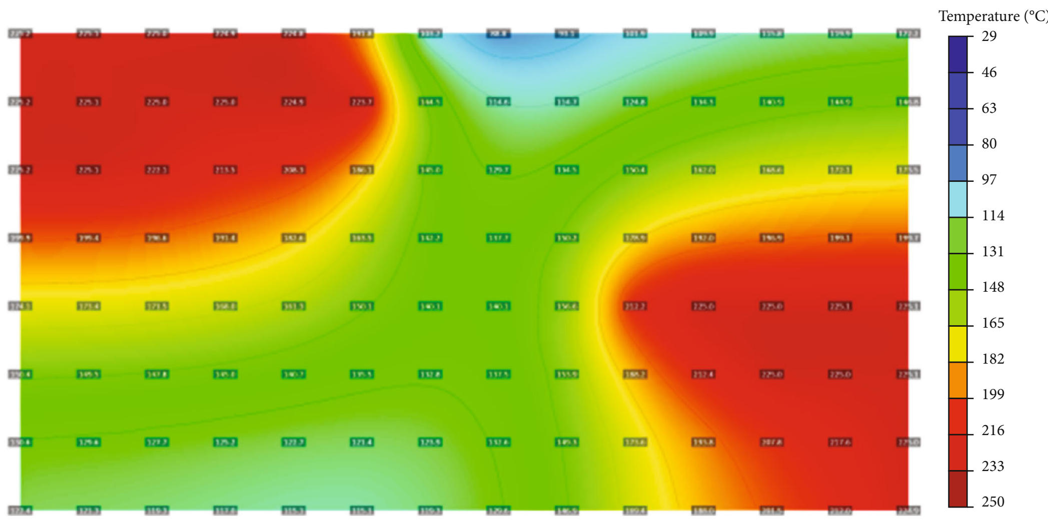
It is far from enough for the implementation of infilled vertical well LASER-assisted SAGD based on the physical experimental results, the sensitivity of geologic parameters, and the key injection, and production parameters should be determined simultaneously. To this end, the numerical simulation approach was utilized on the basis of reservoir properties of the target SAGD area, and a typical SAGD wellpair model with infilled vertical wells was selected to optimize the operational parameters. CMG-STARS thermal simulator was chosen to run the cases. The viscosity of oil and solvent at different temperatures and the key properties of used solvent were carefully analyzed and integrated into the data file.

4.1. Model. According to the well configuration and parameters of the target reservoir, a homogenous model was built by using the CMG-STARS simulator. The geologic parameters such as initial oil saturation, porosity, and permeability were equal to the average values of the target reservoir. The dimensions of the model were $46 \times 27 \times 15 = 18{,}630$, and the grid size in I direction along horizontal length varies in different section, where it is 2.22 m in infilled well vicinity, 6.67 m in interbedded section, and 20 m in noninterbedded section, respectively. The grid size in J direction also varies from 0.5 m to 5 m, with the smallest size in SAGD wellpair vicinity. The grid size in Z direction varies from 1 m in SAGD interwell zone to 1.5 m above the SAGD injector. Therefore, the thickness of the model is 19 m, the width is 70 m, and the horizontal length is 400 m. Table 2 lists the parameters of the model, oil, and solvent K-value coefficients, which reflects the HTHP phase behaviors of the solvent oil. In the model, there is a SAGD wellpair and 6 infilled vertical wells evenly deployed along the horizontal length in the interbedded section. The well spacing of neighboring vertical wells is 60 m, and the spacing between the infilled vertical well and SAGD wellpair is 35 m.

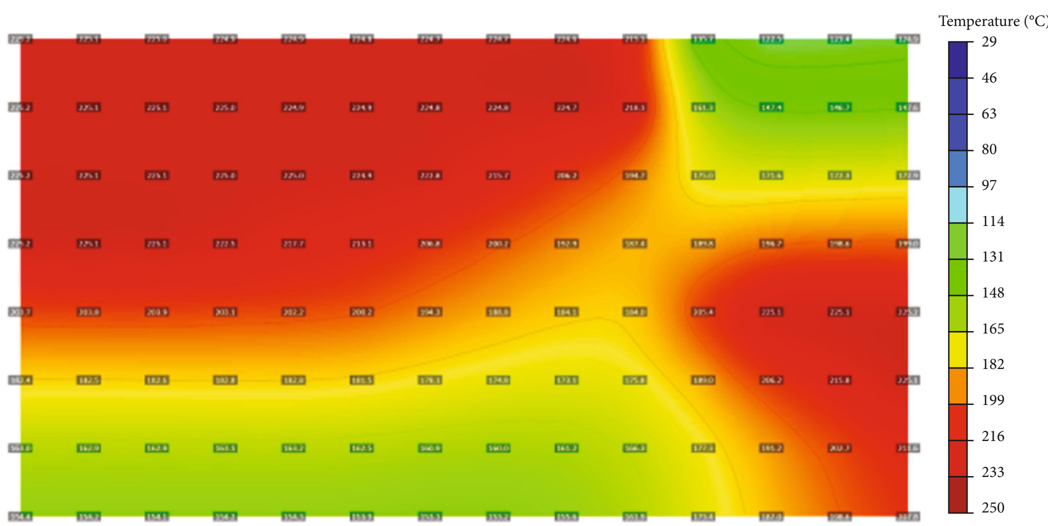
The perforation section of infilled vertical wells is 14 m in the upper position of the payzone, and the vertical spacing between the SAGD injector and producer is 5 m, and the SAGD producer is located 0.5 m above the bottom.

The schematic of the model and well configuration is shown in Figure 13. In field application, conventional CSS for the vertical wells are generally operated before the continuous steam injection process to drive the unswept oil to the SAGD producer. Based on the experimental results, 10 and 4 cycles of CSS and LASER were determined for the infilled vertical wells, respectively. Then, the vertical wells were converted to continuous steam injection.

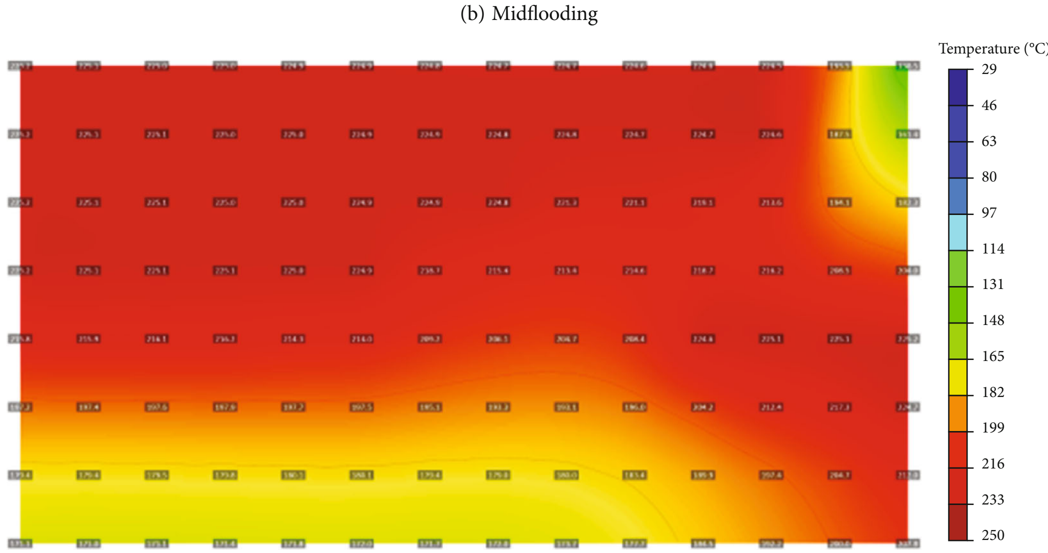
According to the three-axial tests, the fracturing pressure of the overburden is 8 MPa; therefore, the maximal injection pressure of vertical wells is 7 MPa, 1 MPa lower than the fracturing pressure. The bottom-hole pressure in the SAGD



(a) Early flooding



(b) Midflooding



(c) Flooding end

Figure 11: Temperature distribution of vertical-assisted SAGD preheated by LASER.

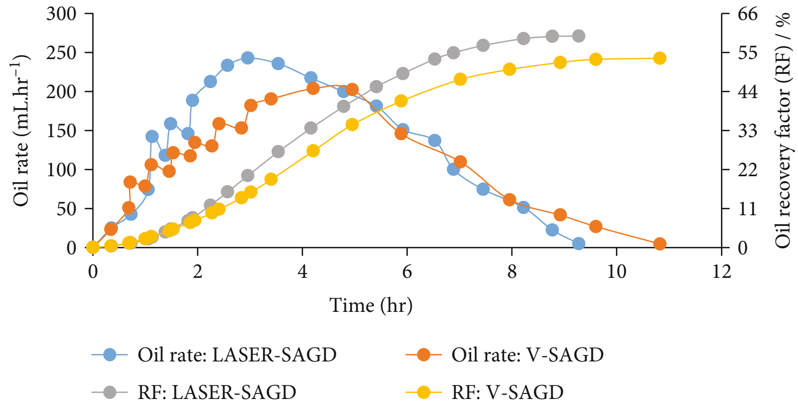
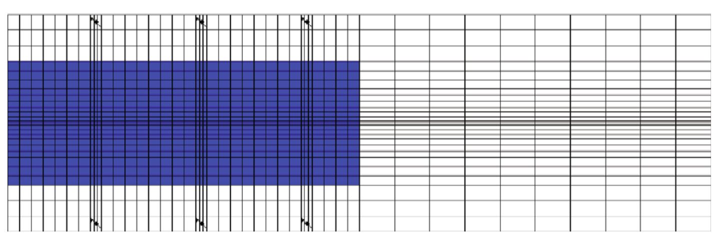


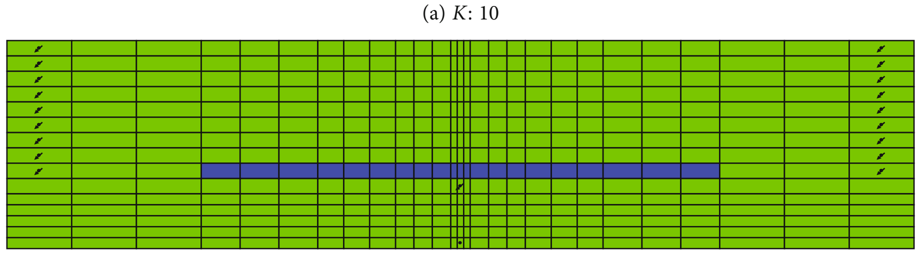
Figure 12: Dynamics comparison of different CSS-assisted SAGD.

Table 2: Parameters of the model and fluid.

Parameters	Value	Parameters	Value
Depth (m)	-250	Oil viscosity@50°C (mPa.s)	11232
Netpay thickness (m)	19	Initial pressure (MPa)	2.5
Initial oil saturation (%)	76	Initial temperature (MPa)	24
Permeability (mD)	1300	Model width (m)	70
Porosity (%)	32	Model length (m)	400
Interbed width (m)	40	Interbed length (m)	200
Solvent coefficient KV1 (kPa)	$1.016^{*}10^{6}$	Solvent coefficient KV4 (°C)	-2737.15
Solvent coefficient KV5 (°C)	-218.17		



(a) *K*: 10



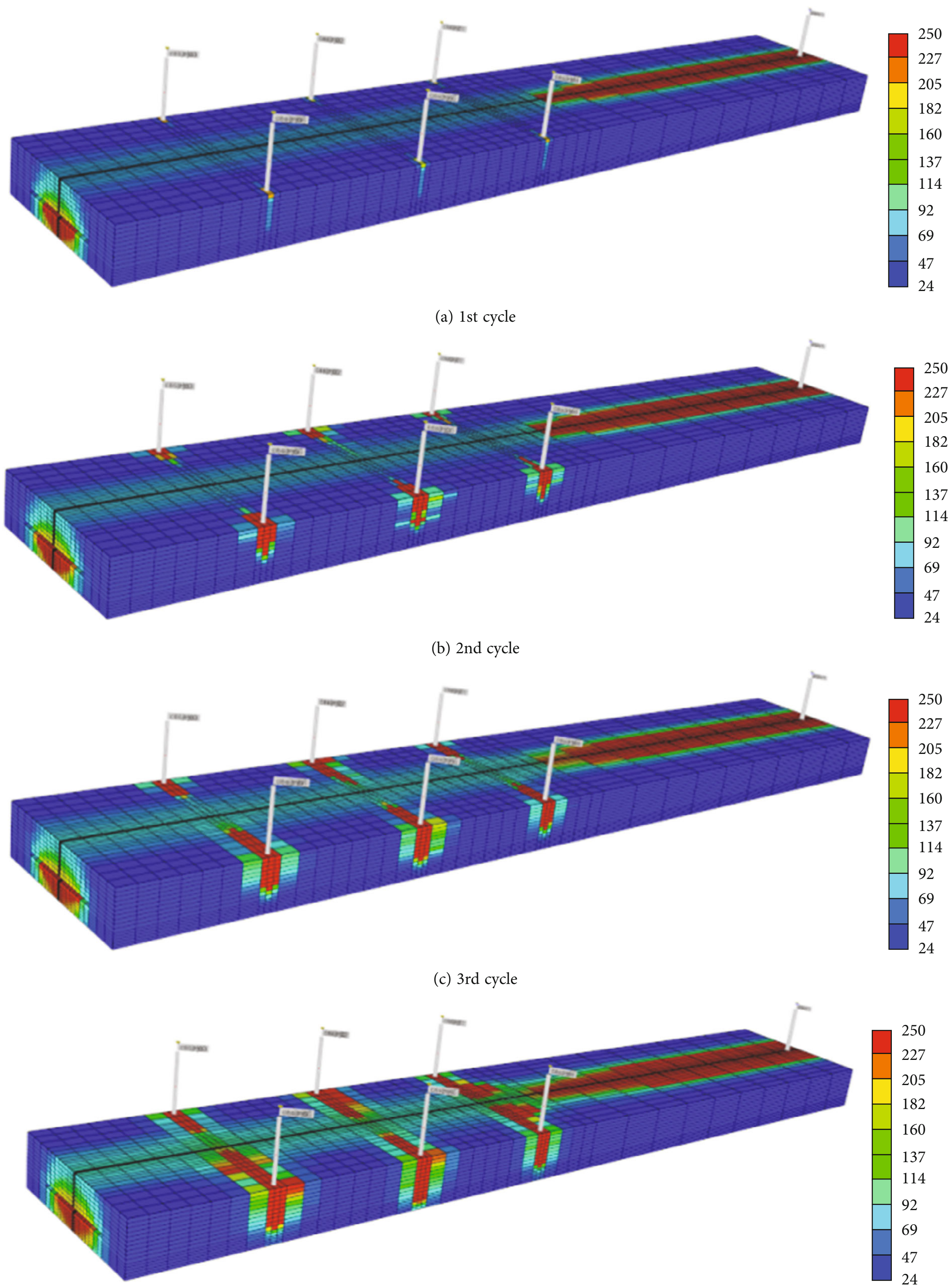
(b) *I*: 9

Figure 13: Schematic of well configuration in the model.

producer is 2.5 MPa, and the injection pressure of SAGD injector is 3 MPa. During the cyclic steam injection period, the maximal steam injection rate is 50 m^3/day, and the solvent proportion is 8 wt%. 3 cases were simulated and analyzed: SAGD, CSS-SAGD, and LASER-SAGD.

4.2. Results and Discussion

4.2.1. Steam Chamber Evolution. During preheating phase of LASER-SAGD, it is shown in Figure 14 that the heated radius of the vertical wells increases cycle by cycle. As the first cycle is mainly the well vicinity preheating, the fluid injected is limited, and the heated radius is just within 10 m. In the second cycle, it is shown that the heated region likes a circle, with no effect of current SAGD steam chamber and producer, due to the far distance of the current heat sources. While during the third cycle, the injected steam tends to connect the current steam-heated region of the SAGD wellpair, and the heat region does not like a circle, with longer heated section perpendicular to the horizontal well and shorter section parallel



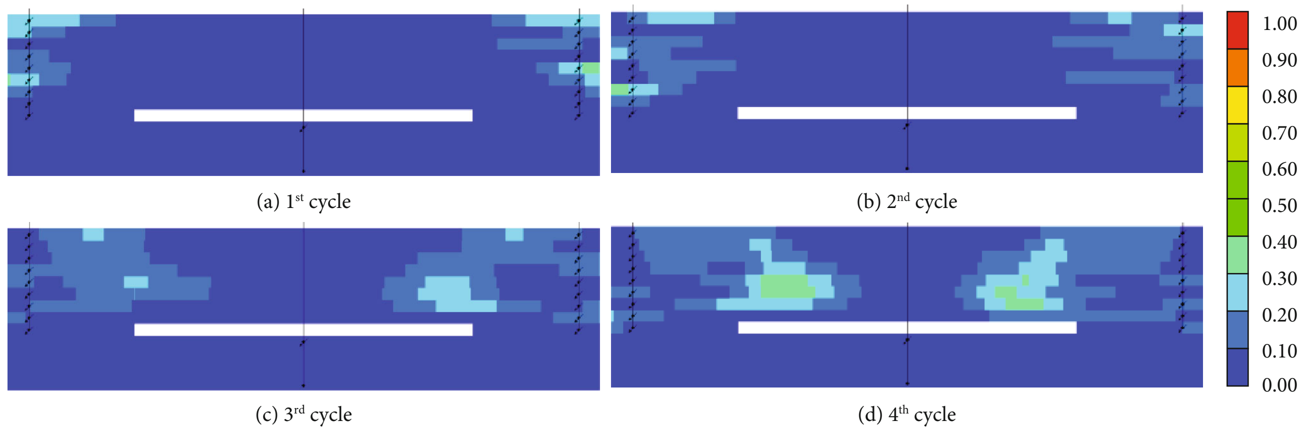
(a) 1st cycle

(b) 2nd cycle

(c) 3rd cycle

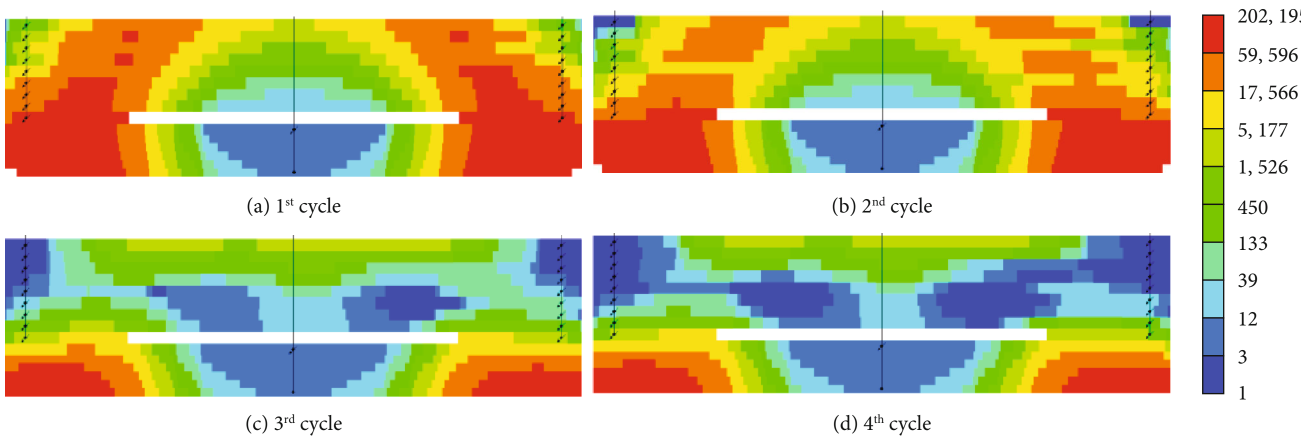
(d) 4th cycle

Figure 14: Temperature fields of different cycles.



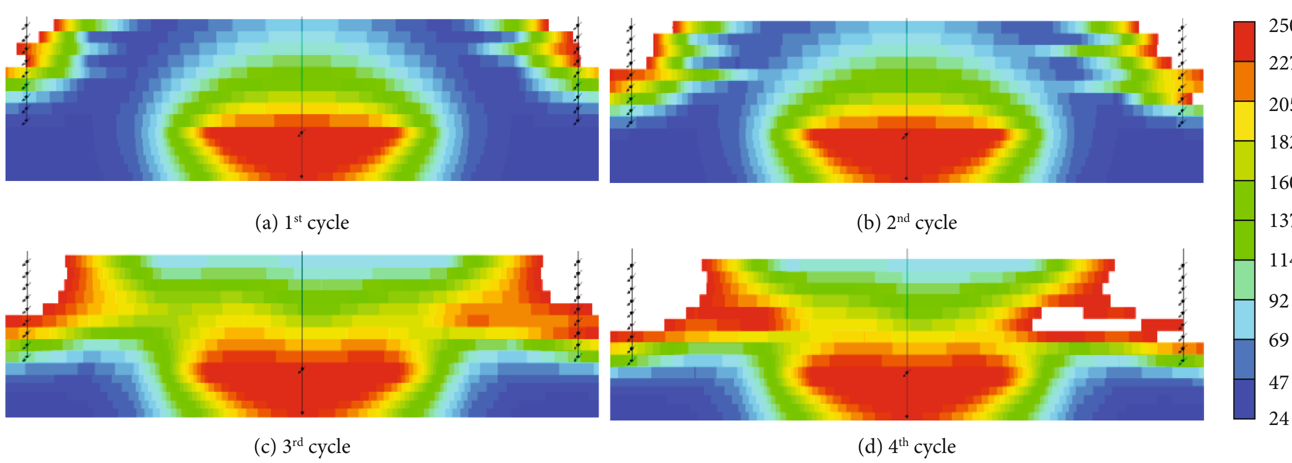
(a) 1st cycle (b) 2nd cycle (c) 3rd cycle (d) 4th cycle

Figure 15: Solvent mole fraction in oil of different cycles.



(a) 1st cycle (b) 2nd cycle (c) 3rd cycle (d) 4th cycle

Figure 16: Oil viscosity at the end of injection of different cycles.



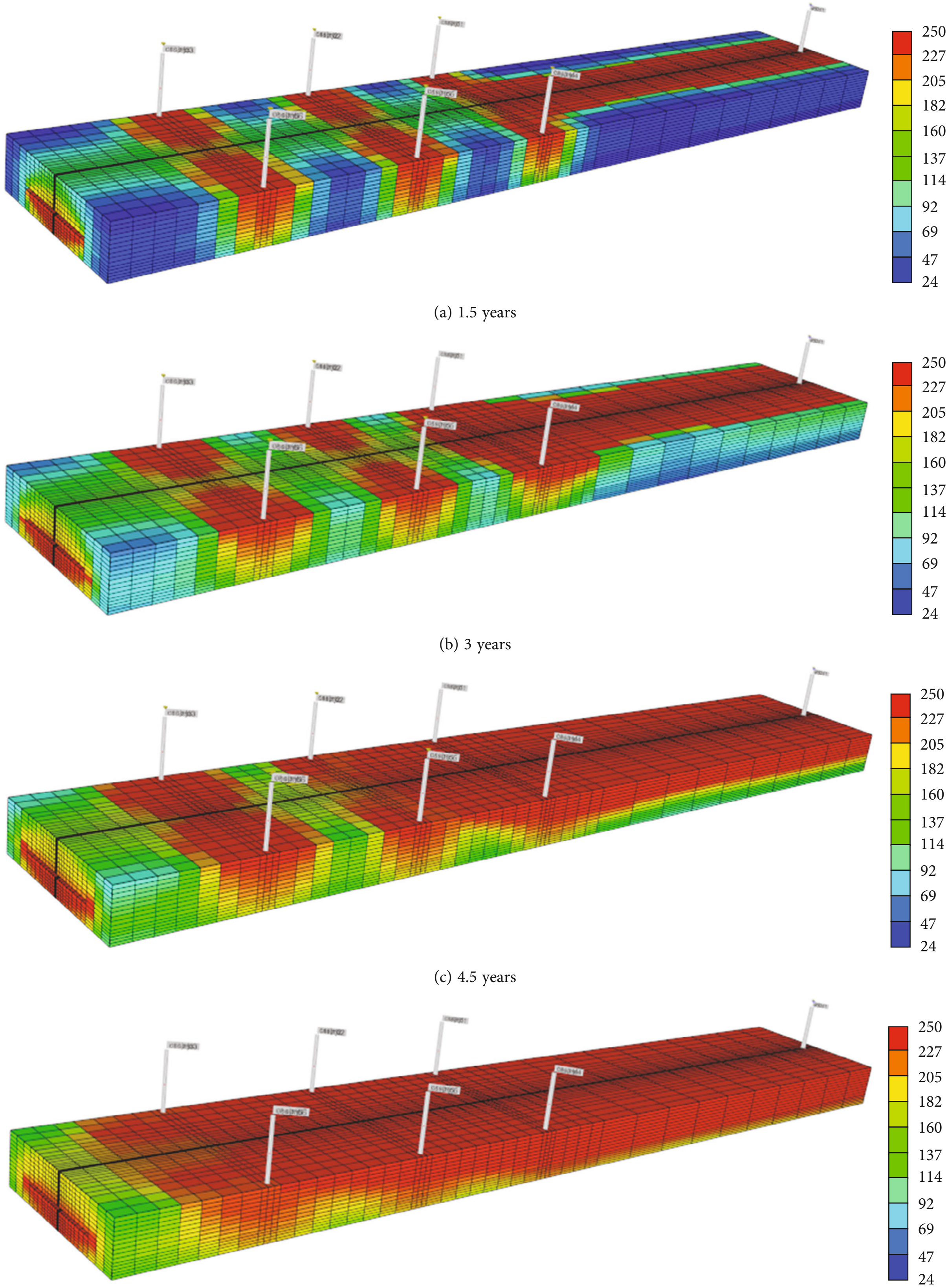
(a) 1st cycle (b) 2nd cycle (c) 3rd cycle (d) 4th cycle

Figure 17: Temperature profiles at the end of injection of different cycles.

to the horizontal well. In the fourth cycle, the temperature profile shows that the injected fluid has contacted with the SAGD steam chamber, meaning that it is timing to convert the vertical wells to continuous injection mode.

From solvent mole fraction profile in different cycles (Figure 15), it is shown that in the first two cycles, the solvent enters the formation with steam simultaneously, while in the third and fourth cycles, the previous injected solvent and the newly injected solvent accumulate in the steam front to further reduce the flow resistance, hence enlarges the heated radius.

The oil viscosity profile in different cycles indicates the importance of solvent (Figure 16), as the oil viscosity is



(a) 1.5 years

(b) 3 years

(c) 4.5 years

(d) 6 years

Figure 18: Temperature fields at different time.

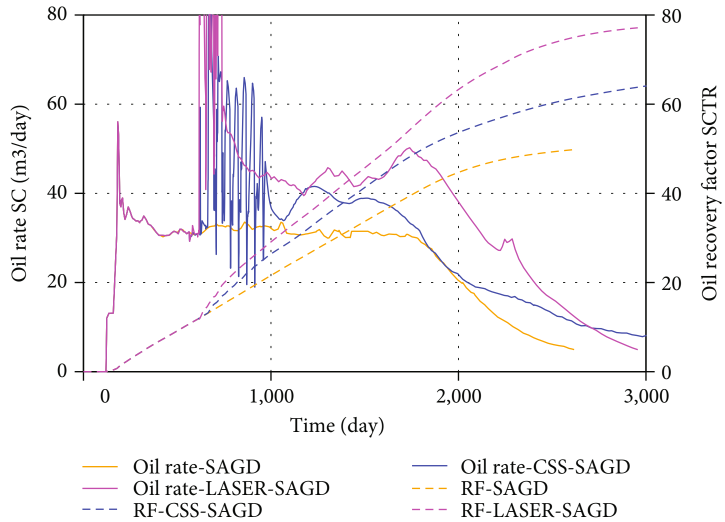


FIGURE 19: Production performance comparison for different recovery methods.

effectively reduced in the high solvent concentration region. From temperature profiles (Figure 17), it is also evident that the steam is easier to enter into regions where the solvent accumulates. At the end of fluid injection in the 4th cycle, the high temperature fluid has connected with the existing steam chamber, indicating that the preheating process has completed.

After vertical well was converted to continuous steam injection mode, the existing SAGD steam chamber plays a key role in combining it with the newly formed vertical-well steam chamber and form an increasingly larger oil drainage area, which contributes to a higher oil rate and longer production lifetime. From the steam chamber evolution map at different flooding time (Figure 18), the untapped oil is mobilized and recovered from expansion of existing SAGD steam chamber to the infilled vertical well section step by step, and after 6 years of production, almost all the surpassed oil in the wellgroup is effectively swept and recovered.

4.2.2. Production Performance. In comparison with the production curves of the SAGD and conventional CSS-SAGD (Figure 19), the LASER-SAGD has only 4 cycles of solvent-steam stimulation, while acquires an incremental oil rate of 5.2 m^3/d and 9.8 m^3/d, respectively. The oil recovery factor for three cases is 49.8%, 63.9%, and 77.1%, respectively, indicating that the infilled LASER-SAGD can massively enhance the oil recovery factor by 27.3% on the basis of SAGD, while by adding only 8% solvent into steam in the infilled vertical well stimulation, 6 cycles are reduced, and the oil recovery is further enhanced by 13.2% compared with conventional infilled CSS-SAGD. This result is higher than expected as it is the predesigned ideal numerical model. In real heterogeneous conditions, the performance improvement could be reduced while the method is technically feasible and the potential of incremental oil recovery is significant.

5. Field Application and Potentials

Field practice of infilled LASER-SAGD has been implemented in 4 SAGD wellpairs in F block in Xinjiang oilfield since 2020. In comparison with 9-10 cycles to establish thermal communication between infilled vertical well and existing SAGD steam chamber in this area, only 4-5 cycles of steam huff-n-puff were needed by adding 8-10% solvent, which means that 5 cycles in average were shortened for the infilled wells to take effect. Moreover, the oil rate of infilled LASER-SAGD is enhanced by 17%, and the steam/oil rate is reduced by 0.08 in average, respectively. It is forecasted that the oil recovery factor in this practice can be enhanced by 5-7%, indicating significant technical and economic potentials.

6. Conclusions

Considering the high steam injection pressure of conventional infilled CSS-SAGD and high pressure differentials with that of SAGD steam chamber, the infilled vertical well LASER-SAGD was proposed in this study, which aims to reduce the pressure differentials and shortens the thermal communication time.

The solvent formula optimization method was established, which is based on the oil viscosity reduction and HTHP phase behaviors. The 2# solvent oil with flash point (65.6°C) and 3# solvent oil with high flash point (112.3°C) were selected as preliminary solvent types, and the optimal solvent formula was determined to be the mixture of 2# and 3# solvent oil (volume ratio 3 : 2) through phase behavior tests.

The 2-D scaled physical experiments of conventional infilled CSS-SAGD and LASER-SAGD were designed and carried out, which indicate that the addition of 10% solvent into steam can effectively speed up the thermal communication, reduce the pressure differential, reduce the risks of steam channeling, enhance the fluid injection capacity, lower the porous fluid flow resistance with less time for the infilled wells to take effect, higher oil rate level, and oil recovery factor. The main reason for this advantage lies in its due oil viscosity reduction mechanisms by solvent dissolution and high temperature steam.

Numerical simulation uses the average field parameters to compare the LASER-SAGD with SAGD and conventional CSS-SAGD, which indicates that the preheating cycle was shorten by 6 cycles, with incremental oil recovery factor of 27.3% and 13.2%, respectively.

The field application shows that encouraging performance has achieved by adding small proportion of solvent into steam to initiate the thermal communication between the infilled injector and SAGD wellpair with 3 shortened cycles. Long-term effect of this practice is also validated by prediction based on the current production dynamics, which shows an incremental oil recovery factor of 5-7%.

Data Availability

The raw/processed data required to reproduce these findings cannot be shared at this time as the data also forms part of an ongoing study.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

Acknowledgments

The authors gratefully acknowledge the financial support of the China National Key Project (2016ZX05031) and the Science and Technology Project of China National Petroleum Corporation (2019B-1411 and 2021DJ1403).

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