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Steam Chamber Expansion and Recovery Mechanisms in Heavy Oil Reservoirs with Multiple Barriers: Experimental and Numerical Study

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Abstract

This study examines the influence of the spatial distribution and geometry of multiple shale barriers on steam chamber development during steam-assisted gravity drainage (SAGD), with particular attention to heating and drainage between adjacent barriers. Two three-dimensional physical model experiments were conducted with vertically stacked barriers directly above the injector (Experiment A) or to one side of the well pair (Experiment B). A laboratory-scale CMG-STARs model was used to examine barrier height, vertical spacing and length. Experiment A exhibited a temporary oil-rate decline followed by renewed production after steam bypassed the barrier edges. Experiment B reached peak production earlier, followed by sustained decline as the chamber spread laterally into the barriers. Despite its lower early oil production rate, A achieved a final experimental recovery factor of 59.5%, compared with 56.4% in B. Temperature profiles showed that chamber growth preceded substantial heating of the oil-sand layers between barriers. The simulations indicated that raising barriers beside the well pair enlarged the heated region beneath them. Closer spacing and greater barrier length were associated with preferential heating outside the barriers while the

intervening layers remained cooler. Together, the temperature and production histories suggest that delayed oil mobilization between barriers contributed to sustained later production in A. These findings distinguish the resumption of steam chamber growth from thermal sweep between barriers and show why early oil production alone did not predict final recovery in the two experiments.

Keywords: Steam-assisted gravity drainage; Shale barriers; Three-dimensional physical modeling; Steam chamber development

1. Introduction

Steam-assisted gravity drainage (SAGD) recovers heavy oil and bitumen through steam heating and gravity drainage to a horizontal producer [1–4]. Its performance depends on steam chamber development and the drainage of mobilized oil to the production well. Previous studies have examined multilateral well configurations, water-bearing layers, wellbore dynamics and dipping reservoirs [5–8], together with steam chamber prediction and operating-parameter optimization [9,10]. In layered heavy-oil reservoirs, interlayer communication and nonuniform heating complicate production behavior [11,12]. Shale barriers are particularly important because their continuity and position affect both steam migration and oil drainage [13–16]. Understanding these coupled effects is necessary to interpret production performance in reservoirs containing multiple barriers.

Yang and Butler [17] experimentally demonstrated that short horizontal barriers delayed steam chamber growth and peak oil production but had little effect on final recovery under their test conditions. They also observed restricted drainage of heated bitumen above a barrier. Kisman and Yeung [18] subsequently obtained comparable trends in a two-dimensional numerical study. Barrier effects are not uniformly detrimental: Pooladi-Darvish and Mattar [19] showed that a sealing shale

layer could limit steam contact with an overlying gas cap and reduce heat loss. Chen et al. [20] reported lower oil rates and recovery as shale content increased, whereas Ipek et al. [21] found that extending production could partly offset the effect of long barriers on final recovery. These results indicate that the observed recovery response depends on both reservoir heterogeneity and the duration of production.

Numerical studies have identified barrier position and continuity as key controls on drainage connectivity. Le Ravalec et al. [22] found that the distance between a barrier and the well pair strongly influenced production. Shin and Choe [23] showed that the absence of a connected flow path between injector and producer was especially detrimental. Li et al. [24] related barrier effects to restricted flow and additional heat loss. Dang et al. [25] examined the combined influence of barrier continuity and distance from the well pair, while Wang and Leung [26] distinguished the effects of continuous and discontinuous shale distributions. These findings establish the importance of geometry and connectivity but do not imply a unique production response for all barrier distributions.

Physical studies have also examined the production response to multiple barriers. Using Long Lake oil sands data, Xia et al. [27] found that multiple barriers prolonged lateral steam chamber growth and produced two peaks in the oil production curve. Huang et al. [28] combined physical experiments and numerical simulation to examine barrier permeability and the number of barriers. The barrier nearest the injector strongly affected chamber development, while the number of barriers influenced peak oil production. These observations suggest that successive barrier encounters can redistribute oil production over time, rather than simply reduce the production rate throughout the process.

Zhang et al. [29] investigated shale barriers using theoretical and numerical analysis and reported a 13% increase in cumulative oil production relative to a homogeneous case under their modeled conditions. Their result further illustrates the dependence of recovery on barrier distribution and operating conditions. Three-dimensional experiments by Zhang et al. [30] on discontinuous breccia interlayers showed a thinner steam chamber profile and delayed peak production. Wei et al. [31] also used three-dimensional experiments to investigate SAGD performance under different interlayer distributions. Together, these studies motivate closer examination of heating within the barrier-bearing interval, in addition to the overall extent of the steam chamber.

Recent analytical studies have improved the description of SAGD production stages and heat utilization. Huang et al. [32] incorporated permeability anisotropy and heat transfer into predictions for the plateau and decline stages. Wang et al. [33] developed a multistage model of oil–water flow and heat consumption, and Wang et al. [34] subsequently examined how liquid withdrawal and the production–injection ratio affect thermal energy utilization. For reservoirs containing an interlayer, Nie et al. [35] described successive stages of steam chamber development above the injector. Bai et al. [36] combined experiments and modeling to show that contact with a shale barrier changes heat distribution during the rising stage. These studies link chamber development with production and heat transfer, but local heating between stacked barriers remains important when interpreting the response of heterogeneous reservoirs.

Complementary experimental studies have examined methods for accessing oil affected by barriers. Sheng et al. [37] used a physical model to investigate permeability barriers during steam–solvent coinjection. Dong et al. [38] combined three-dimensional experiments and laboratory-scale simulations to assess a horizontal injector above a shale barrier, demonstrating improved access to

oil above it. Li et al. [39] used two-dimensional visualization to examine flue gas-assisted vertical–horizontal well SAGD, and Sun et al. [40] investigated well patterns and geomechanical dilation in reservoirs containing multiple flow barriers. These approaches modify steam access, fluid mobility or reservoir connectivity. For conventional SAGD, three-dimensional observations are still needed to relate heating between stacked barriers to the oil production response when barriers are encountered during different stages of chamber growth.

The present study focuses on steam chamber development under different spatial distributions and geometries of multiple shale barriers. Two three-dimensional physical model tests compare three stacked barriers directly above the injector with three barriers to one side of the well pair. Temperature profiles and production histories are analyzed together to relate the chamber rising and lateral spreading stages to heating and oil drainage between adjacent barriers. Laboratory-scale CMG-STARs simulations then examine barrier height, vertical spacing and length. The combined analysis distinguishes renewed chamber advance after steam bypass from thermal sweep within the intervening layers and relates this difference to the production response. Section 2 presents the experiments and their results; Section 3 presents the numerical model and sensitivity analysis; Section 4 summarizes the findings.

2. Physical model experiments

2.1 Experimental design

2.1.1 Model scaling and design parameters

The laboratory design was based on thermal-recovery scaling principles and published studies of horizontal-well physical models [41–45]. The Pujol–Boberg framework [41] provides a reference

for steam-injection scaling, while Eqs. (1)–(3) present the SAGD relationships adopted from Butler [2]. These expressions were used as design guidance. Geometric dimensions, fluid properties and heat-transfer conditions were not all scaled by a common factor.

$$B_3 = \sqrt{\frac{kgH}{\alpha\phi\Delta S_o m v_s}} \quad (1)$$

$$t_D = \frac{t}{L} \sqrt{\frac{kg\alpha}{\phi\Delta S_o m v_s H}} \quad (2)$$

$$q = L \sqrt{\frac{2\alpha\phi kgh}{m v_s}} \quad (3)$$

Practical constraints also limited the permeability attainable in the sand pack. The following Reynolds-number expression was considered as a simplified screening calculation for model permeability:

$$R_e = \rho v D / \mu \quad (4)$$

Under a local, single-phase, gravity-dominated Darcy-flow approximation, neglecting the pressure-gradient contribution and taking relative permeability as unity, the magnitude of the Darcy velocity is

$$v = \frac{K}{\mu} \cdot \rho \cdot g \quad (5)$$

Combining Eqs. (4) and (5) gives

$$R_e = \frac{K \rho^2 D g}{\mu^2} \quad (6)$$

where Re is the Reynolds number, ρ is fluid density, v is Darcy velocity, μ is dynamic viscosity, K is absolute permeability, g is gravitational acceleration and D is the characteristic length. The estimate depends on the definitions of D and velocity. Because Eqs. (5) and (6) omit pressure gradients, phase-dependent relative permeability and steam–water–oil interactions, they do not establish dynamic similarity for the multiphase SAGD process.

Table 1 compares the Long Lake field reference parameters with the laboratory design values. The oil-sand thickness and vertical injector – producer separation have field-to-model length ratios

of 250, whereas the corresponding ratios for well length, well radius and barrier thickness are 2000, approximately 16.7 and 200, respectively. The design therefore uses nonuniform geometric scaling. The selected sand-pack permeability is $40 \mu\text{m}^2$. These choices support investigation of chamber development and production trends at laboratory scale; quantitative prediction of field performance requires a separate assessment of thermal and multiphase-flow scaling.

Table 1. Field reference parameters and laboratory design values.

	Parameters	Field scale	Lab scale
Basic parameters	Oil-sand thickness (m; <i>cm</i>)	30	12
	Vertical injector–producer separation (m; <i>cm</i>)	5	2
	Well radius (m; <i>cm</i>)	0.1	0.6
	Well length (m; <i>cm</i>)	800	40
	Producer standoff above the reservoir base (m; <i>cm</i>)	3	1.2
	Barrier thickness (m; <i>cm</i>)	1	0.5
	Oil saturation (%)	85	85
	Porosity (%)	33	33
	Oil-sand permeability (μm^2)	5	40
	Initial temperature (°C)	7	20
	Steam temperature (°C)	220	220
	Steam quality (%)	80	80
	Initial pressure (<i>MPa</i>)	1.5	1.5
SAGD	Steam chamber pressure (<i>MPa</i>)	2.2	2.2
	Design production-time correspondence (a; <i>min</i>)	1	87.6
	Design preheating-time correspondence (a; <i>min</i>)	0.5	44

Parameters	Field scale	Lab scale
Nominal steam injection rate (m^3/d ; mL/min)	300	40

2.1.2 Distribution of multiple barriers

Two barrier distributions were selected to examine restrictions encountered during the steam chamber rising and lateral spreading stages (Table 2). Figures 1 and 2 show the barrier locations and model dimensions. Experiment A contains three horizontal barriers directly above the injector, with equal vertical spacing. In Experiment B, three horizontal barriers extend from one lateral model boundary toward the well pair, leaving the oil sand directly above the injector unobstructed. The barrier lengths are 10 cm in A and 12 cm in B. The tests therefore compare two distributions that differ in both barrier location and lateral extent.

Table 2. Barrier locations in the physical model tests.

Experiment	Barrier location
A	Barriers directly above the injector
B	Barriers to one side of the well pair

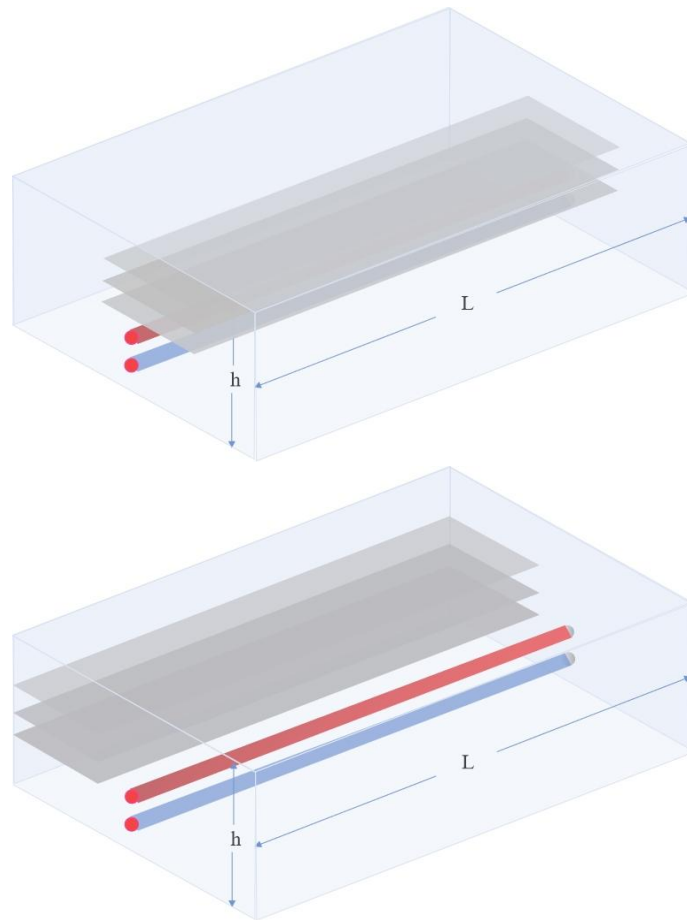
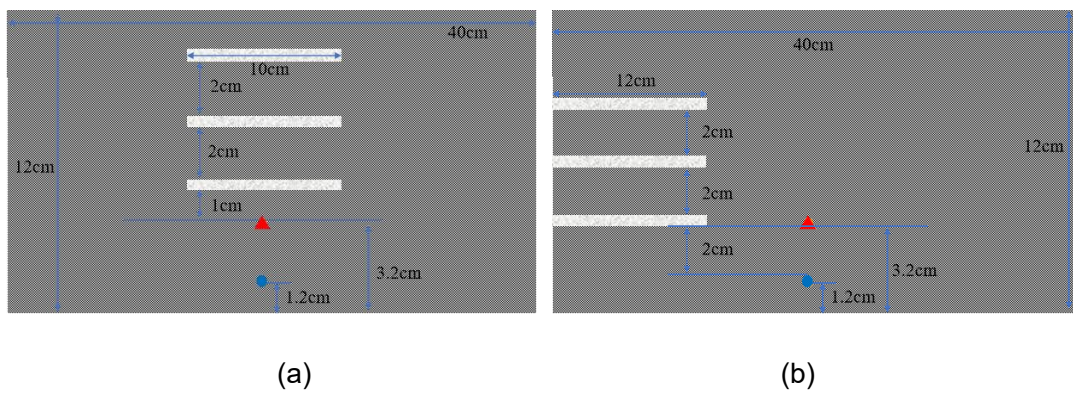


Fig. 1. Barrier distributions in the physical models: directly above the injector in Experiment A (upper) and to one side of the well pair in Experiment B (lower).



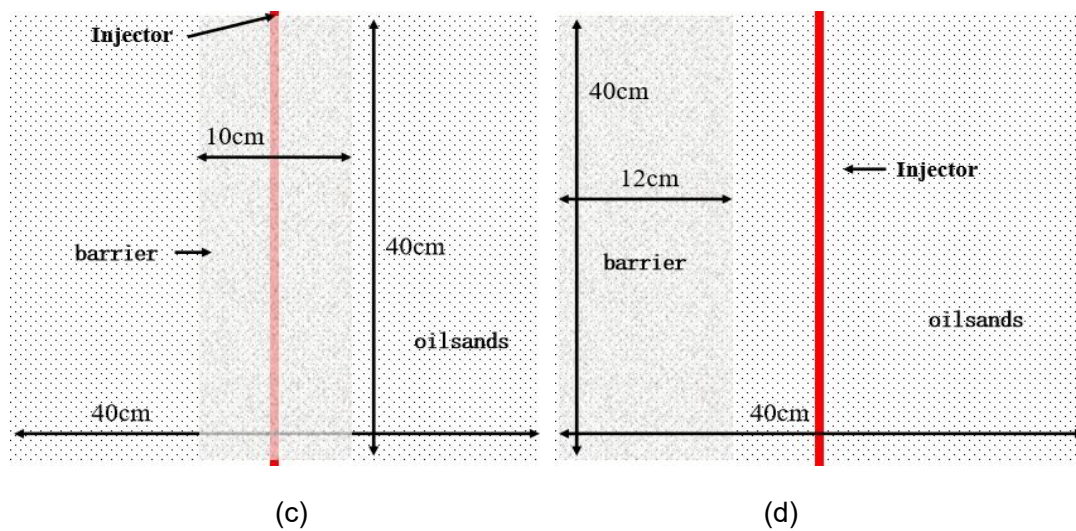


Fig. 2. Barrier geometry and well locations: (a, b) vertical sections and (c, d) plan views of Experiments A and B, respectively. Dimensions are in cm.

2.2 Experimental materials

Cleaned and screened 20-mesh quartz sand was used to prepare the sand pack. The oil was obtained from the Long Lake region in Canada (Fig. 4). Its temperature-dependent viscosity is represented by the viscosity–temperature curve in Fig. 3. Cement layers were embedded in the sand pack to represent shale barriers and restrict cross-layer flow. They reproduce a prescribed barrier geometry; equivalence between the petrophysical and thermal properties of cement and natural shale is not assumed.

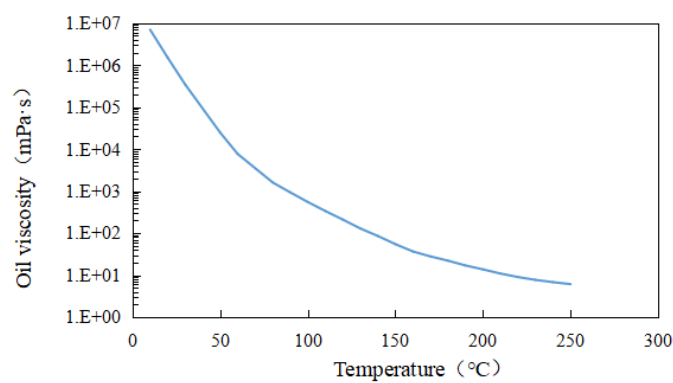


Fig. 3. Oil viscosity as a function of temperature.



Fig. 4. Oil sample used in the experiments.

2.3 Experimental apparatus

Figure 5 shows the experimental system, comprising a steam-generation unit, a three-dimensional physical model and a data-acquisition system. The model vessel is housed in a constant-temperature cabinet and has an internal side length of 40 cm (Fig. 6). The oil-sand layer measures 40 cm $\times$ 40 cm $\times$ 12 cm. The cabinet limits changes in the external thermal environment, although heat loss from the vessel remains possible. Fine steel tubing was wrapped around the injector and producer for preheating (Fig. 7). Steam was supplied by an injection pump and steam generator, and exposed pipelines were wrapped with heating bands to reduce heat loss before injection.

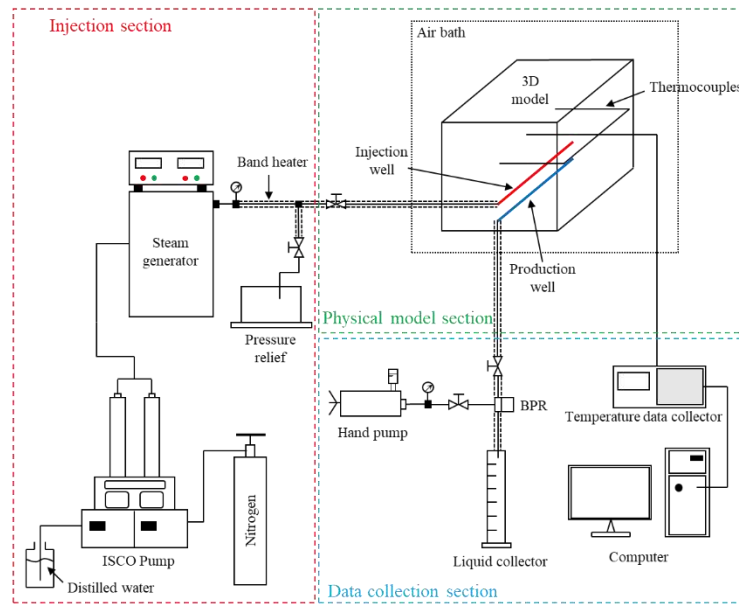


Fig. 5. Schematic of the experimental apparatus [9].



Fig. 6. Three-dimensional physical model.

2.4 Experimental procedures

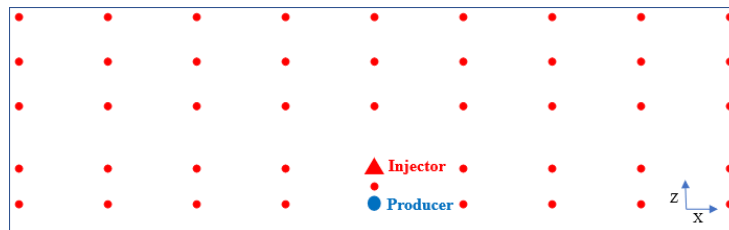
The experimental procedure consisted of five steps: preparation, model filling, sealing, saturation and SAGD operation.

- (1) Experimental preparation. Quartz sand was cleaned to remove impurities and then dried. Oil and water were mixed at a ratio of 85:15 and combined with the sand. The steam generator and pipeline connections were checked before each test.

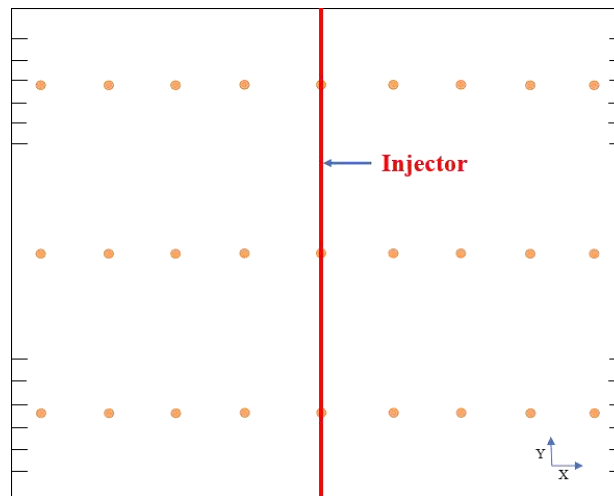
- (2) Model packing. The horizontal well pair and preheating tubing were positioned near the base of the oil-sand layer (Fig. 7). Temperature sensors were installed at the locations shown in Fig. 8. The underburden, oil-sand pack, cement barriers and overburden were placed according to the model design.
- (3) Model sealing. A pressure-hold test was performed after assembly. The acceptance criterion was a pressure decrease of no more than 0.1 MPa over 12 h.
- (4) Model saturation. Heated oil was injected through the model ports to distribute oil through the sand pack and expel air. The steam generator, temperature acquisition system and back-pressure valve were then connected. The design porosity and initial oil saturation were 33% and 85%, respectively (Table 1).
- (5) SAGD operation. The well pair was preheated until the temperature between the injector and producer reached 90 °C. Steam injection began after the injection-line pressure exceeded the model pressure. The nominal laboratory conditions were an initial temperature of 20 °C, an initial pressure of 1.5 MPa, a steam temperature of 220 °C, a steam quality of 80%, a steam chamber pressure of 2.2 MPa and an injection rate of 40 mL/min (Table 1). Produced liquid and model temperatures were monitored during the test. Production was terminated when the produced-fluid water cut exceeded 98%. The final experimental recovery factor refers to this endpoint and is not an estimate of ultimate recovery.



Fig. 7. Preheating tubing around the horizontal well pair.



(a) Vertical plane



(b) Horizontal plane

Fig. 8. Temperature sensor locations in the vertical and horizontal planes.

2.5 Results and discussion

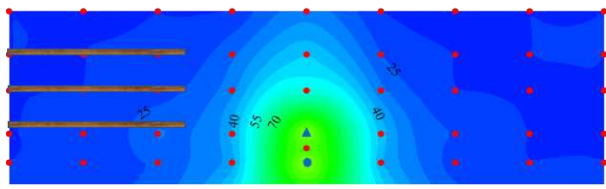
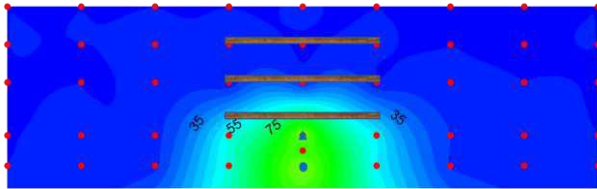
2.5.1 Steam chamber development and heating between barriers

Figure 9 presents temperature profiles during preheating and SAGD operation. Steam chamber development is inferred from these profiles; temperature provides an indication of the heated region rather than a direct measurement of steam saturation or chamber volume. During preheating, the temperature increase in Experiment A was concentrated beneath the barriers above the injector. In Experiment B, heat spread more uniformly around the well pair, where no barrier obstructed the oil sand. The profiles show characteristic stages at the indicated times, which differ between the two experiments.

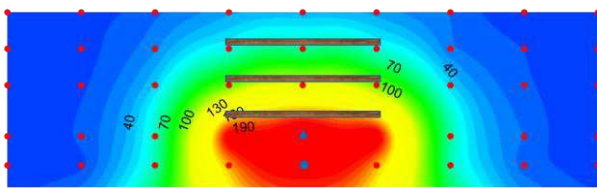
In Experiment A (Fig. 9A), the high-temperature region first spread beneath the lowest barrier. Upward chamber growth resumed after steam reached its edges, and successive barriers produced further lateral diversion. However, the centers of the oil-sand layers between barriers remained cooler even after the surrounding chamber had advanced upward. Steam bypass therefore restored chamber growth before substantial heating of these layers occurred. Restricted steam entry and drainage paths within the barrier-bearing interval offer a possible explanation for this lag. The profiles distinguish the advance of the outer heated region from thermal sweep between adjacent barriers.

In Experiment B (Fig. 9B), the chamber initially rose through the unobstructed oil sand above the injector and subsequently spread laterally toward the barriers. Temperature contours became uneven near the barrier tips, and the heated region extended farther beneath the barriers than into the oil-sand layers between them. The principal restriction developed during lateral spreading, after the

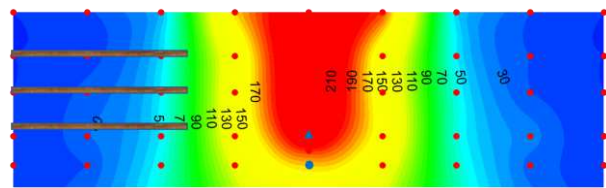
initial rising stage. Thus, an unobstructed rise above the well pair did not ensure uniform heating across the oil-sand layer: cooler zones persisted between the barriers as the surrounding heated region expanded.



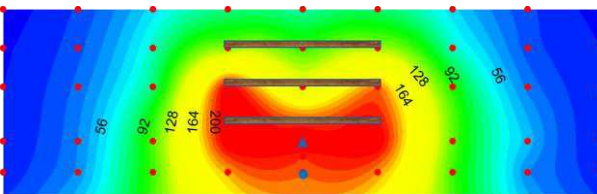
Preheating phase



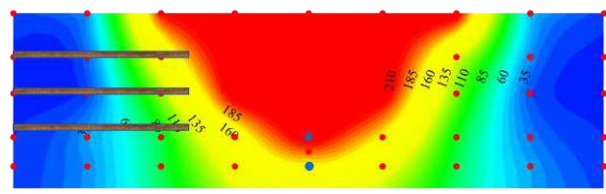
A (110min)



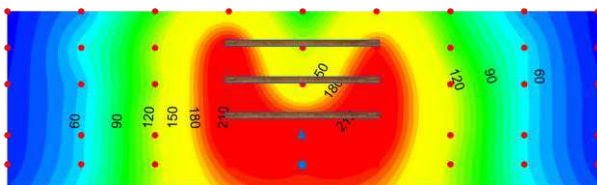
B (100min)



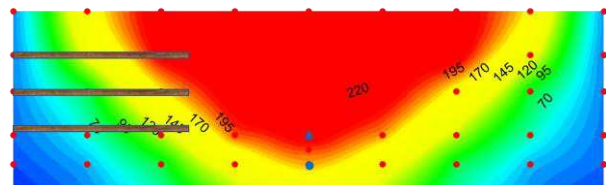
A (150min)



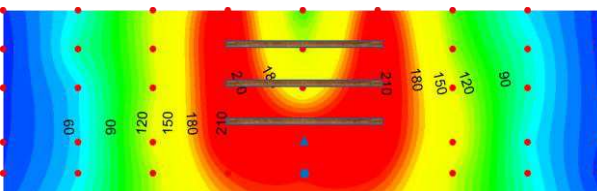
B (200min)



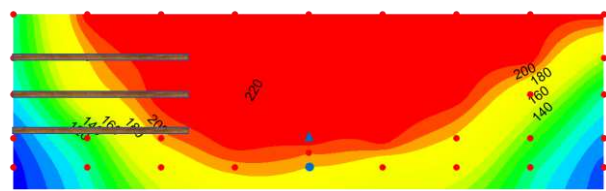
A (190min)



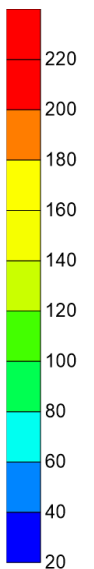
B (260min)



A (220min)



B (400min)



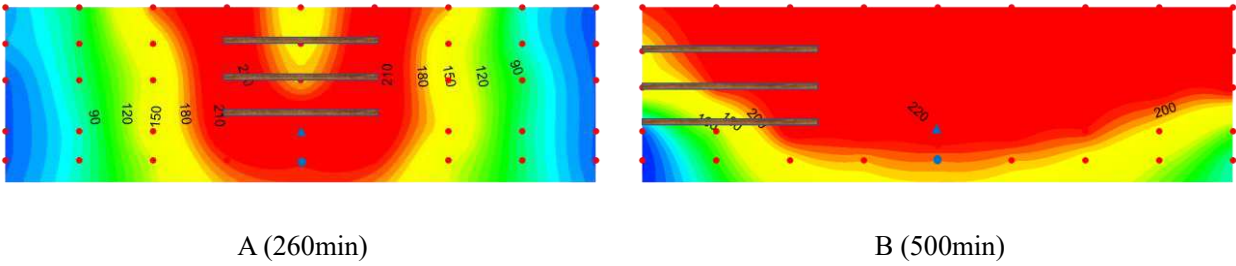


Fig. 9. Experimental temperature profiles for Experiments A and B at the indicated times. The color scale gives temperature in °C.

2.5.2 Effects of barrier distribution on production performance

Figure 10 relates the production history of Experiment A to the temperature profiles. Five stages are identified. (1) Initial ramp-up: the oil rate rises before the chamber encounters the lowest barrier, while water cut increases and then becomes relatively stable. (2) Temporary decline: lateral chamber growth beneath the barrier is accompanied by decreasing oil rate and oil–steam ratio (OSR), with a slight increase in water cut. (3) Gradual recovery: after steam bypasses the barrier edges, upward growth resumes, oil rate and OSR increase, and water cut decreases. (4) Renewed ramp-up: the chamber reaches the top of the oil-sand layer and spreads laterally, accompanied by a further increase in oil rate and OSR. (5) Late decline: oil rate and OSR decrease as drainage proceeds, while water cut rises. The production increase following Stage 2 indicates a temporary restriction on oil mobilization and drainage, followed by access to additional heated oil.

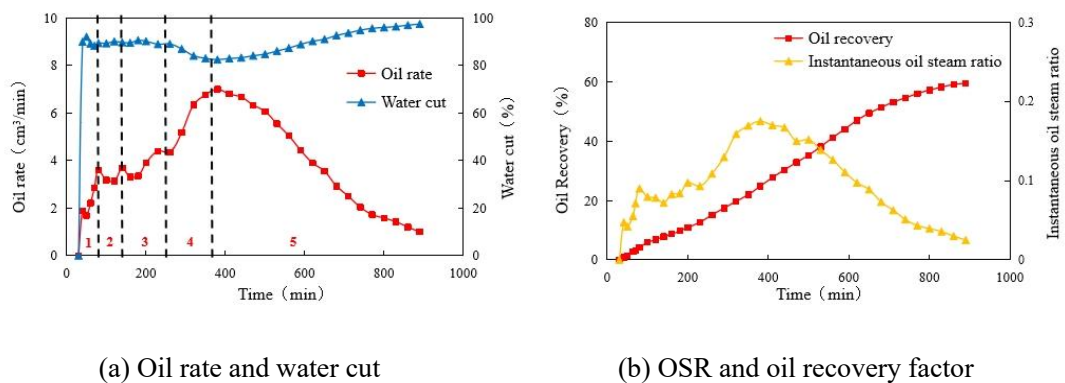


Fig. 10. Production performance of Experiment A: (a) oil rate and water cut; (b) OSR and recovery factor.

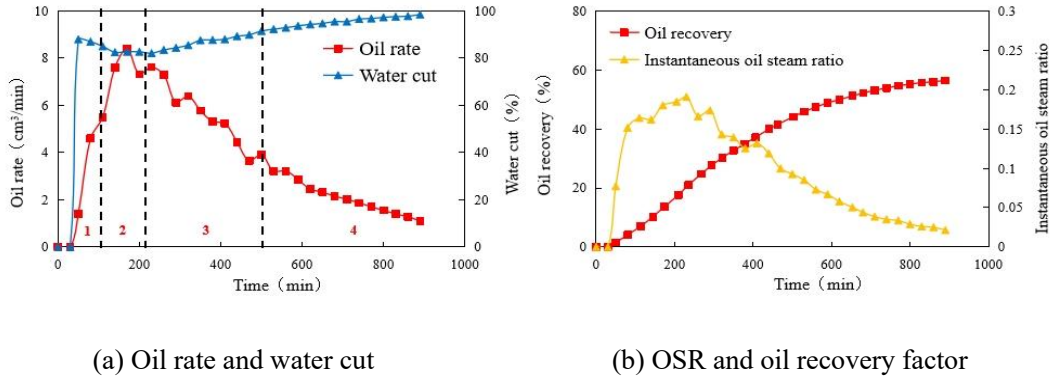


Fig. 11. Production performance of Experiment B: (a) oil rate and water cut; (b) OSR and recovery factor.

Experiment B exhibits four production stages (Fig. 11). (1) Initial ramp-up: upward chamber growth is accompanied by rapidly increasing oil rate and OSR; water cut first rises and then decreases. (2) Peak production: the chamber reaches the top of the oil-sand layer and begins to spread laterally; oil rate fluctuates near its peak, with comparatively stable water cut and OSR. (3) Rapid decline: as the laterally spreading chamber encounters barriers at different elevations, oil rate and OSR decrease, water cut increases and cumulative recovery rises more slowly. (4) Gradual decline: the chamber continues to develop beneath the barriers, and changes in production become less pronounced. The post-peak decline is not followed by a sustained oil-rate recovery, in contrast to the temporary decline in Experiment A.

The early production advantage of Experiment B did not persist to the experimental endpoint (Figs. 10 and 11). Experiment A reached peak production later, but sustained oil production during the later stages compensated for its early shortfall. The final recovery factors were 59.5% in A and 56.4% in B, a difference of 3.1 percentage points. Progressive heating between barriers in A is consistent

with delayed oil mobilization and the later production increase, although the temperature profiles cannot apportion produced oil among individual layers. The comparison shows that early oil rate alone did not predict endpoint recovery in these tests. Because barrier location and length both differed, and the tests were not replicated, the recovery difference cannot be assigned to barrier location alone or interpreted as a statistically established effect.

3. Numerical simulation

3.1 Numerical model

A laboratory-scale thermal reservoir model was constructed in CMG-STARs to represent the three-dimensional experiments. The oil-sand domain measures 40 cm $\times$ 40 cm $\times$ 12 cm and contains 20 $\times$ 20 $\times$ 24 grid cells, each measuring 2 cm $\times$ 2 cm $\times$ 0.5 cm. Figure 12 identifies the steel shell, cap layer, insulation, oil sand and barriers in gray, yellow, black, red and dark blue, respectively. The shell was represented as a no-flow boundary; the gray and yellow regions were specified as inactive cells in the model setup. Table 3 lists model properties, including the thermal conductivities, and Fig. 13 shows the oil–water relative permeability curves. The model is used for comparisons of chamber development at the experimental scale.

Three dimensionless geometric parameters define the sensitivity cases. Barrier height (Parameter 1) is the vertical distance from the injector to the lowest barrier normalized by the 12 cm oil-sand thickness. Vertical barrier spacing (Parameter 2) is the distance between adjacent barriers normalized by the same thickness. Barrier length (Parameter 3) is normalized by the 40 cm lateral model width: lengths of 10 and 12 cm correspond to ratios of 0.25 and 0.30, respectively. This lateral reference length is distinct from the 2 cm vertical separation of the injector and producer. Table 4

lists 18 cases: Models 1–9 contain barriers directly above the injector, and Models I–IX contain barriers to one side of the well pair. Within each three-case group, one geometric parameter is varied and the other two are held fixed.

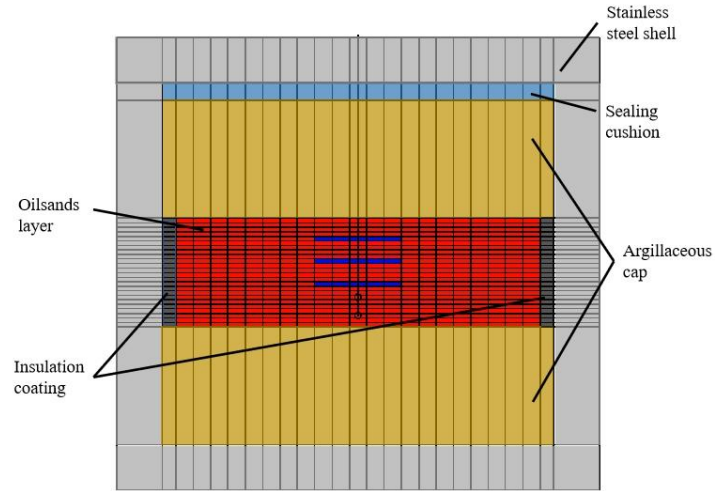


Fig. 12. Schematic of the laboratory-scale numerical simulation model.

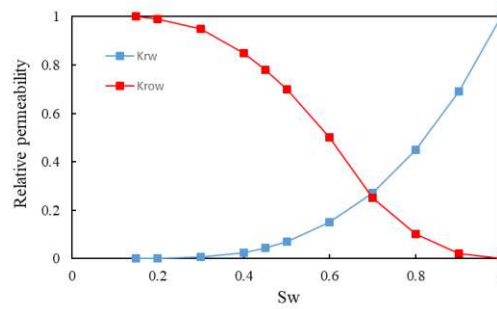


Fig. 13. Oil–water relative permeability curves.

Table 3. Numerical model parameters.

Parameters	Value	Unit
Oil-sand permeability	40	μm^2
Barrier thermal conductivity	0.682	$\text{J}/(\text{cm}\cdot\text{min}\cdot^\circ\text{C})$
Water thermal conductivity	0.37	$\text{J}/(\text{cm}\cdot\text{min}\cdot^\circ\text{C})$
Oil thermal conductivity	0.18	$\text{J}/(\text{cm}\cdot\text{min}\cdot^\circ\text{C})$

Parameters	Value	Unit
Initial temperature	20	°C
Cap-layer thermal conductivity	0.42	$J/(cm \cdot min \cdot ^\circ C)$
Rock thermal conductivity	1.4	$J/(cm \cdot min \cdot ^\circ C)$

Table 4. Geometric parameters for barriers directly above the injector (Models 1–9) and to one side of the well pair (Models I–IX).

Model	Height ratio	Spacing ratio	Length ratio	Model	Height ratio	Spacing ratio	Length ratio
1	0.083	0.167	0.25	I	0	0.167	0.3
2	0.167	0.167	0.25	II	0.083	0.167	0.3
3	0.25	0.167	0.25	III	0.167	0.167	0.3
4	0.083	0.083	0.5	IV	0.083	0.083	0.25
5	0.083	0.167	0.5	V	0.083	0.167	0.25
6	0.083	0.25	0.5	VI	0.083	0.25	0.25
7	0.167	0.167	0.2	VII	0.083	0.208	0.125
8	0.167	0.167	0.5	VIII	0.083	0.208	0.25
9	0.167	0.167	0.8	IX	0.083	0.208	0.4

3.2 Comparison with experimental data

Figure 14 compares experimental and simulated oil rate, water cut and cumulative oil production.

The model captures the main production trends, while Fig. 15 tests whether it also represents the spatial development of heating. At 200 min, the simulated heated region is larger than the

experimental region. Differences in heat loss may contribute to this discrepancy, but their contribution has not been quantified. The later profiles reproduce the diversion of the heated region around the barriers. Agreement is assessed qualitatively from these production and temperature comparisons; no quantitative history-matching error or independent validation is available. The following sensitivity analysis therefore supports interpretation of heating patterns rather than calibrated forecasts of recovery.

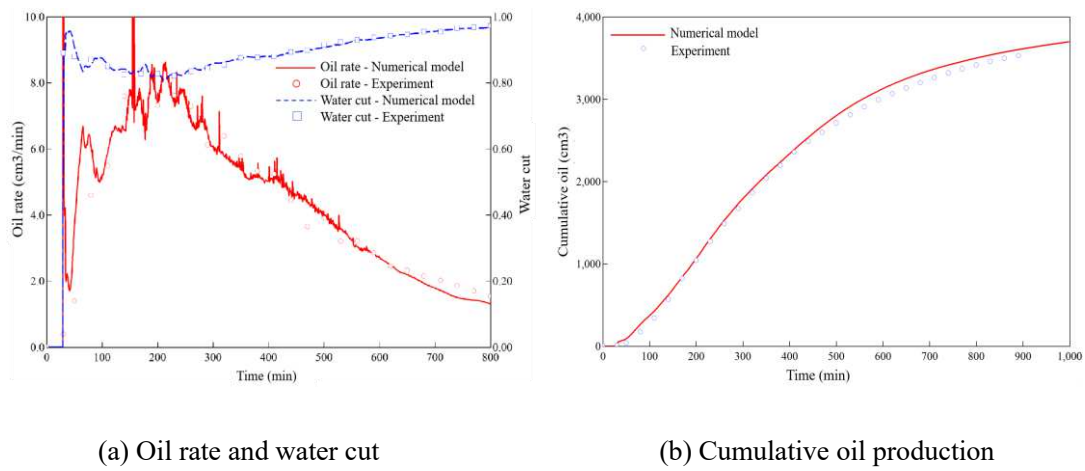
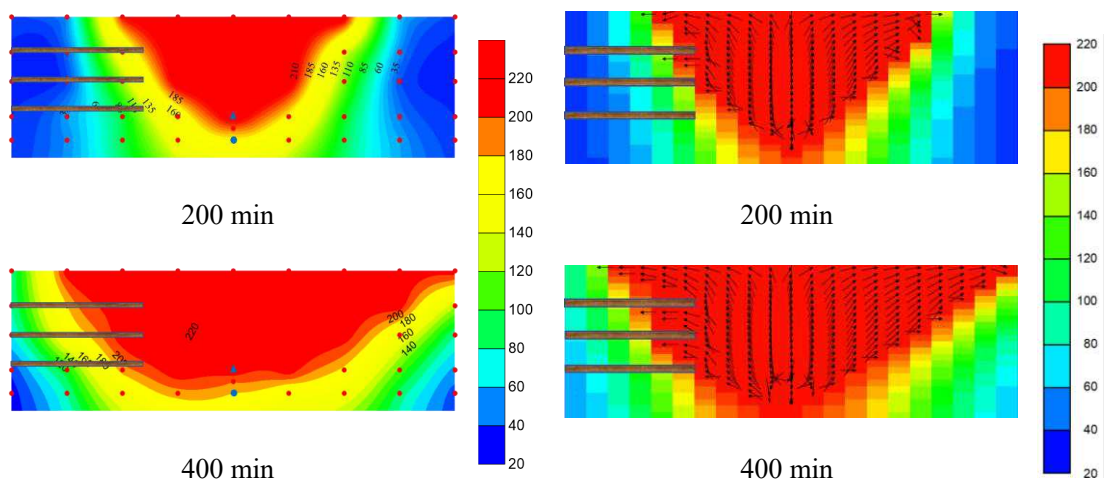


Fig. 14. Comparison of experimental and simulated production: (a) oil rate and water cut; (b) cumulative oil production. Water cut is expressed as a fraction in panel (a).



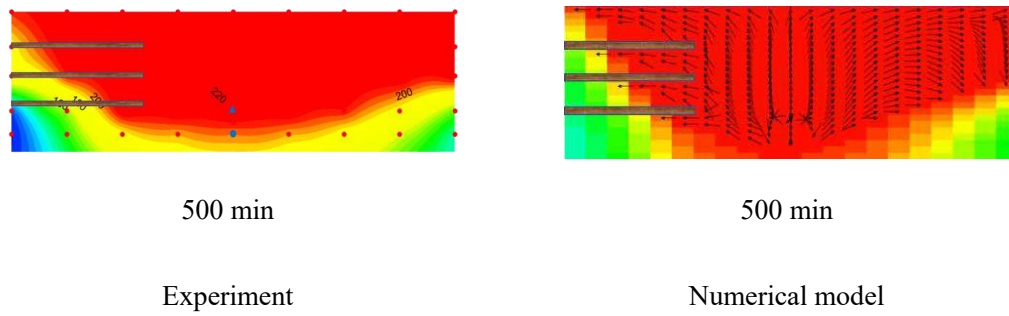
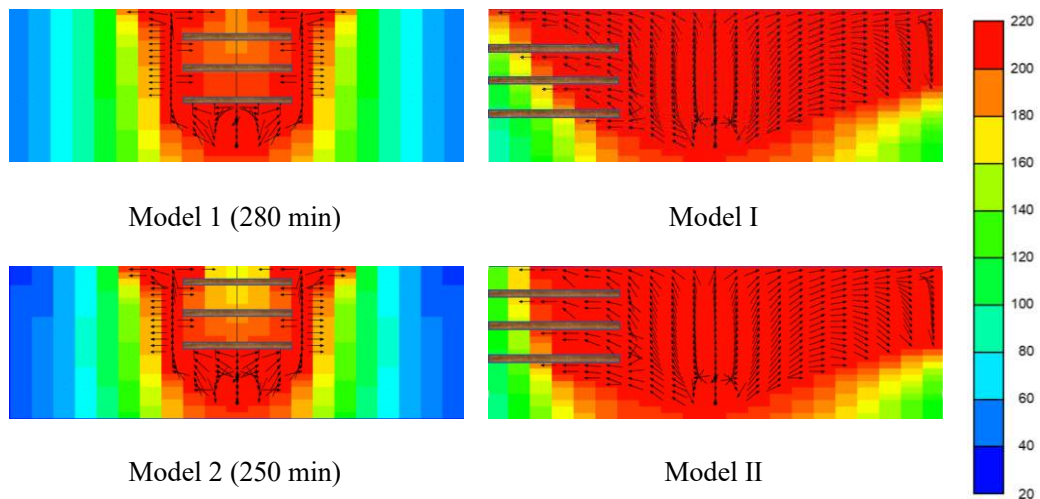
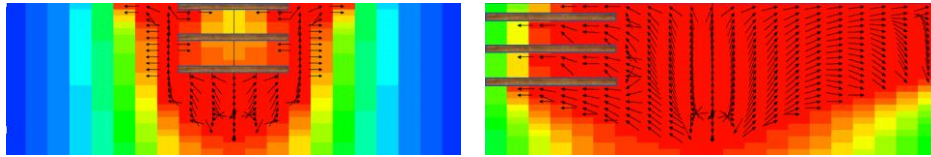


Fig. 15. Experimental and simulated temperature profiles at 200, 400 and 500 min. The color scale gives temperature in °C.

3.3 Effects of barrier geometry on steam chamber development

Figure 16 shows how barrier elevation changes the distribution of heating. In Models 1–3, the chamber develops beneath the lowest barrier, bypasses its edges and then heats the layers above. The profiles at 280, 250 and 220 min illustrate different stages and cannot be used to compare chamber volumes at a common time. In Models I–III, raising the barriers beside the well pair enlarges the oil-sand interval below the lowest barrier and reduces the interval above the uppermost barrier. Heating consequently extends farther beneath the barriers, while its upward extent is limited by the top of the oil-sand layer. The result is a redistribution of the heated region toward the lower interval; it does not by itself demonstrate improved recovery from the oil sand between barriers.





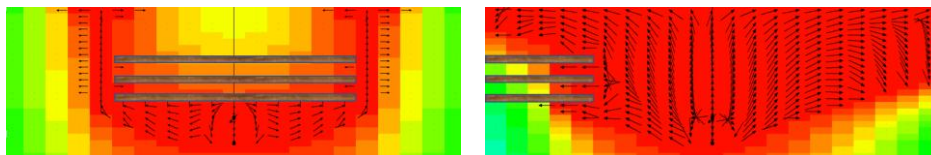
Model 3 (220 min)

Model III

Fig. 16. Simulated temperature profiles for different barrier heights: Models 1–3 (left) and I–III (right). Temperature is in °C.

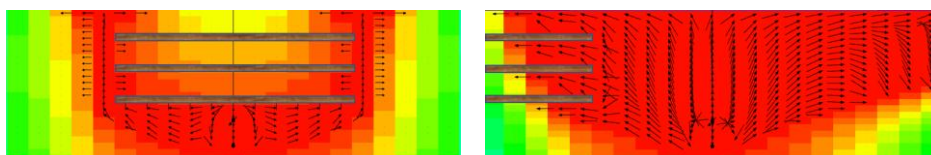
Figure 17 examines vertical barrier spacing. For barriers directly above the injector (Models 4–6), wider spacing provides a thicker oil-sand interval in which heating develops after steam bypasses the barrier edges. At smaller spacings, the surrounding heated region grows while the thinner layers between barriers remain cooler. Restricted drainage within these layers may delay steam entry and oil mobilization. Because the amount of oil sand between barriers also changes with spacing, a larger heated area cannot be interpreted directly as a higher recovery efficiency.

For barriers to one side of the well pair (Models IV–VI), closer spacing produces a more uneven temperature distribution. Heating develops preferentially in the thicker oil-sand intervals above and below the barriers, while the intervening layers remain cooler. Thus, lateral chamber growth outside the barriers can coexist with limited thermal sweep between them. This spatial separation helps explain why overall chamber extent alone is an incomplete measure of oil mobilization within a barrier-bearing interval.



Model 4

Model IV



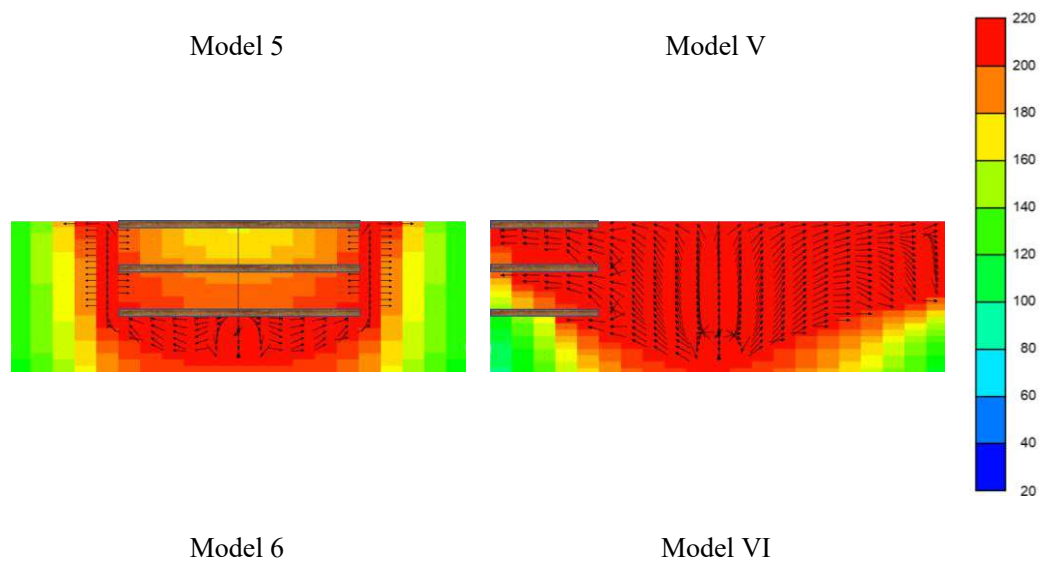
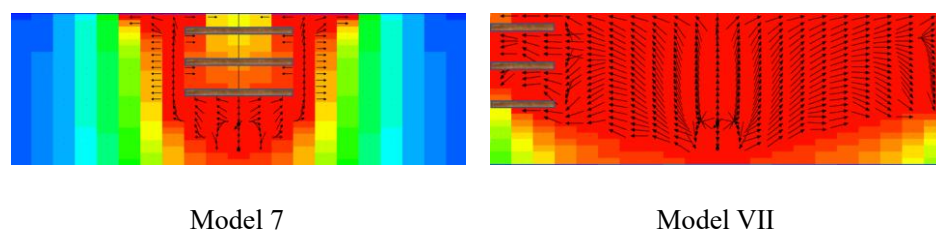


Fig. 17. Simulated temperature profiles for different vertical barrier spacings: Models 4–6 (left) and IV–VI (right). Temperature is in °C.

Figure 18 shows that barrier length affects where oil sand remains poorly heated. With barriers directly above the injector (Models 7–9), cooler zones persist near the centers of the intervening layers as barrier length increases, even after steam has bypassed the edges. Chamber advance outside these longer barriers therefore does not imply that the oil sand enclosed vertically by them has been heated uniformly. For barriers beside the well pair (Models VII–IX), longer barriers extend closer to the injector and are encountered earlier during lateral spreading. Heating then develops preferentially beneath them, leaving cooler oil sand between adjacent barriers. Across the height, spacing and length cases, the common feature is a divergence between heating outside the barriers and heating within the intervening oil-sand layers. These temperature patterns identify potential restrictions on oil mobilization, but do not establish a field-scale well-placement criterion.



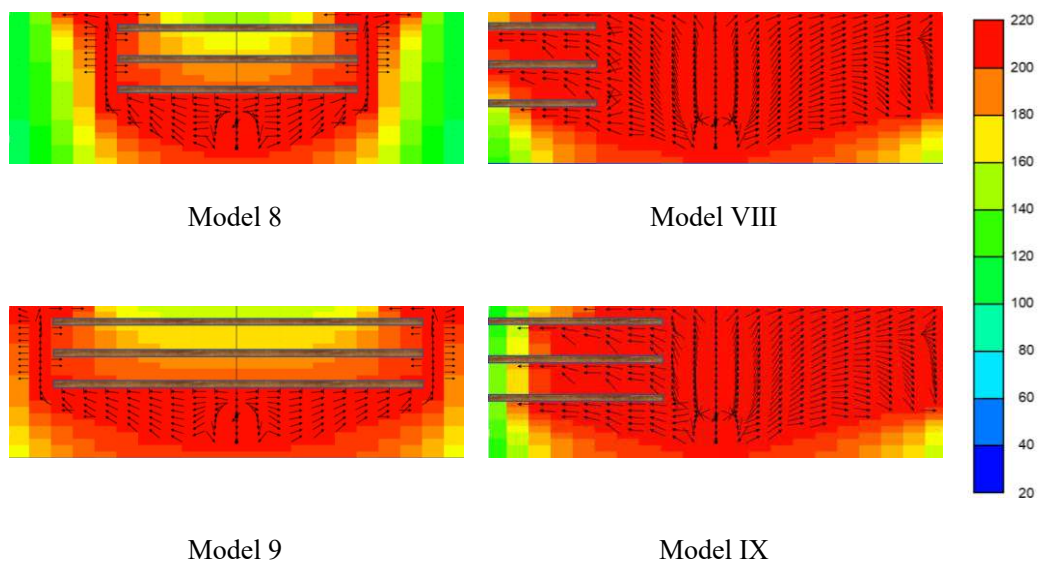


Fig. 18. Simulated temperature profiles for different barrier lengths: Models 7–9 (left) and VII–IX (right). Temperature is in °C.

4. Conclusions

Three-dimensional physical model experiments and laboratory-scale CMG-STARs simulations were used to investigate SAGD under different barrier distributions and geometries. The following conclusions were obtained:

- (1) With barriers directly above the injector, five production stages were identified, including a temporary oil-rate decline and renewed production after steam bypass. Barriers to one side of the well pair produced four stages, with sustained decline after lateral chamber contact.
- (2) Steam bypass restored upward chamber growth before substantial heating of the oil-sand layers between barriers. Cooler zones persisted within these layers as the surrounding heated region expanded. The observed lag shows that renewed chamber advance does not indicate effective thermal sweep throughout the barrier-bearing interval.
- (3) Experiment A reached peak production later but achieved 59.5% recovery, compared with 56.4% in Experiment B. Sustained later production compensated for its lower early oil rate. The temperature and production histories suggest that progressive heating between barriers contributed to delayed oil mobilization and the later production increase.
- (4) The simulations showed that raising barriers beside the well pair enlarged the heated interval beneath them. In both barrier distributions, closer spacing and greater length favored heating outside the barriers while the intervening oil-sand layers remained cooler. These responses show how barrier geometry redistributes thermal sweep within the barrier-bearing interval.

Conflict of interest statement

The authors declare no conflict of interest.

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