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A Novel Solvent Injection Technique for Enhanced Heavy Oil Recovery: Cyclic Production with Continuous Solvent Injection

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Abstract

Solvent-based in-situ enhance oil recovery (EOR) techniques are extensively studied to improve oil recovery factors (RFs) for heavy oil reservoirs. Continuous injection, such as vapour extraction (VAPEX), and cyclic injection, such as cyclic solvent injection (CSI) are two main categories of solvent EOR techniques. The production rates of VAPEX are low in field tests. CSI does not show exciting results due to the quick reservoir pressure depletion and the sudden reservoir energy loss, which causes the oil to regain its viscosity.

A new enhanced heavy oil recovery technique, cyclic production with continuous solvent injection (CPCSI), is proposed in this paper. In this process, a vapour solvent is continuously injected into the reservoir to maintain reservoir pressure and also supply extra gas drive to flood the diluted oil out through an injector that is located on the top of the reservoir, while a producer, which is located at the bottom of the reservoir, is operated in a shut-in/open cyclic way. A series of experiments have been conducted to validate the CPCSI performance by using different sand-pack models with 4–5 Darcy permeability, and saturated with Western Canada heavy oil sample. Gaseous propane is continuously injected through an injector at a constant pressure, which is below the dew point pressure, and producer was operated with a cycle of 50-minute-shut-in/10-minute-open period.

Experimental results show that, the oil is diluted and drained down by gravity during shut-in period, then produced in producer opening period by solution gas drive and gas flush. In comparison with VAPEX and CSI, CPCSI offers free gas driving, and still keeps oil diluted in the well opening period and produced by the gas flush. The RFs are up to 85% of OOIP in 1-D tests. Also, shorter height model has highest average production rate in comparison with others. Test results are also validated by 2-D physical model, in which the RF is improved by 11% by using the lateral CPCSI compared with classic lateral VAPEX. Well configurations and the shut-in/open scenarios are key optimization factors that affect CPCSI performance.

This work shows that CPCSI could be an alternative optimization production scenario for applying solvent based in-situ EOR techniques for Western Canada heavy oil reservoirs.

Introduction

Heavy oil and bitumen resource is the key to fulfill nowadays increasing demand of hydrocarbon fuels consumption all over the world. The untapped heavy oil and bitumen deposits are over five times than the remaining conventional crude oil reserves, and are estimated at 5.6 trillion barrels (Herron and King 2004). Canada contributes about 50 percent of these untapped heavy hydrocarbon deposits, which are located in Western Canadian Sedimentary Basin. Thermal methods, such as steam flooding, cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD), have been widely applied in the fields to reduce the heavy oil viscosity. However, for the reservoir with thin net-pay, in presence of bottom water zone and/or with high water saturation in the pay zone, the thermal methods tend to be neither effective nor economical due to significant heat loss and large heating and water source requirement (Butler and Mokrys 1991; Yazdani and Maini 1993; Knorr and Imran 2011).

Non-thermal methods, including surface mining, cold heavy oil production (CHOP) or cold heavy oil production with sands (CHOPS), and solvent injection, are the other main techniques that are used for recovering heavy oil. Surface mining is effective but it is only economically applicable to those reservoirs with a depth less than 70 metre. Only about 5% of the heavy oil reservoirs can be recovered with this technique (Jiang 1997). CHOP/CHOPS can recover approximate 5%–10% of the initial heavy oil in place, and this process would become uneconomical because the pressure depletion and water encroachment (Ivory et al. 2010). Solvent injections, such as vapour extraction (VAPEX) and cyclic solvent injection (CSI), use a vapourized solvent to extract heavy oil or bitumen deposits. A pure light hydrocarbon or a mixture of several pure light hydrocarbons is usually used as the solvent. The injected gaseous solvent is dissolved into the heavy oil to reduce the oil viscosity, in-situ de-asphaltening, and the diluted oil can be produced by gravity drainage or pressure depletion (Butler and Mokrys 1991; Ivory et al. 2010; Mokrys and Butler 1993).

In general, the solvent injection processes can be categorized into two groups: VAPEX is a continuous solvent injection process; and CSI is a cyclic solvent injection and production process. VAPEX process has been extensively studied by many researchers (Butler and Mokrys 1989; Butler and Mokrys 1993; Butler and Mokrys 1991; Mokrys and Butler 1993; Yazdani and Maini 1993; Jiang 1997). The VAPEX process is gravity dominated, so it is not effective in thin reservoirs due to the lack of gravity drainage. Low production rates were observed in field tests. Previous studies also indicate that the lateral well pattern in VAPEX process is useful for recovering thin reservoirs (Butler and Jiang 2000). The solvent is dissolved into the oil and once the heavy oil viscosity is reduced, the diluted oil will be drained by gravity and a small pressure difference (Knorr and Imran 2011). The traditional CSI process is also known as solvent huff-n-puff process, which comprises of an injection cycle, a soaking period and a production cycle (Lim et al. 1996; Dong et al. 2006; Ivory et al.2010; Jamaloei et al. 2012). The light hydrocarbon gas is injected into the reservoir to increase the reservoir pressure, part or portion of which is dissolved into the heavy oil to reduce the oil viscosity, and then the reservoir pressure is reduced to produce the diluted oil. The problems of this process are that the pressure drops rapidly so that the diluted oil may regain its viscosity while the dissolved solvent is released from diluted oil and the severe formation energy loss during the pressure depletion. In addition, it needs a longer time for injecting and soaking that may cause the average production to be relatively low in this process.

An enhanced solvent injection EOR technique for heavy oil, cyclic production with continuous solvent injection (CPCSI), was proposed in this study. The performance of CPCSI process was experimentally examined through 1-D and 2-D sand-packed physical models. The experimental results suggest that the RFs are up to 85% of OOIP in 1-D tests. In the 2-D tests, the RF can be improved by 11% by using the CPCSI compared with classic lateral-VAPEX.

Experimental section

Materials

In this study, the heavy oil sample obtained from an oil field located in Western Central Canada was used in all tests. The measured density and viscosity of this dead oil sample were ρ_o= 980 kg/m^3 and μ_o = 8411 mPa·s at atmospheric pressure and constant room temperature of 21 °C, respectively. Asphaltene content of the original heavy oil sample was measured by using the standard ASTM D2007 with No.5 Whatman filter paper with a pore size of 2.5 µm and found to be 18.88 wt.%. Research grade pure propane, purchased from Praxair Canada with 99.99 mol.% purity, was used as a gaseous solvent to extract the heavy oil. Potters glass beads with an average pore size of 90–150 µm was used to pack the physical sand-pack models homogeneously.

Experimental set-up

Two different types of physical models were used in this study to study the performance of the CPCSI process: small cylindrical physical models with different lengths; and a visual rectangular sand-pack high pressure physical model. The cylindrical models were with 3.8 cm in inner diameter and 34 cm, 63 cm and 93 cm in length, respectively. Two caps machined with 1/8 inch NPT ports to provide well placement. The visual rectangular model had a chamber size of 40 x 10 x 2 cm^3 with a thin polycarbonate see-through plate and a thick acrylic glass plate to provide the visual observation during the test. The schematic diagrams of the experimental setup were shown in Figures 1 and 2. The experimental tests were performed in different scenarios, which include 1-D vertical CPCSI, 1-D horizontal CPCSI, 2-D lateral VAPEX and 2-D lateral CPCSI.

The solvent injection system consisted of a propane cylinder, a gas reducing regulator, a digital pressure gauge, a solvent injection valve and an injector. The gas reducing regulator was set to the constant operating pressure for all tests and the propane cylinder was left open to provide continuous gaseous solvent during the entire test. A digital scale with a large scale range (KILO TECH, KWS 301) was used to measure the amount of the solvent injection for the entire test run. The sample collection system was consisted of a producer, a back-pressure regulator (BPR), a ball valve and a sample collecting flask. The back pressure regulator (Equilibar, EB1ZF1) was adjusted to maintain the pre-specified operating pressure. Another digital scale with a small scale range was used to measure the weight of produced cumulative oil. A high-precision digital pressure transducer (HEISE, PM1L, PPM-2-DIGPSI 3000A Sensors) was connected to the model to precisely measure the pressures of both injector and producer simultaneously.

Experimental preparation

Sand-packing: Before packing, the bulk volume of each model was measured. For the 1-D thin tube model, the model was sealed and the filter was properly placed on each port, except that one port was left open on one side of the cap for filling up the glass beads. Dry glass beads were injected into the model through the open port. At the same time, the physical model was shaken with an air-actuated vibrator and the void space would be formed on the top of the model when the loose glass beads were shaken downward. Once the void space was formed and observed, more glass beads would be added through the open port until the glass beads did not do downward anymore. Then the port was sealed. For the 2-D physical model, the model was sealed and the filters were applied for all ports, except that one port was left open for filling up the beads. Then the same procedure was followed as it was for 1-D model.

Porosity measurement: The imbibition method was used to measure the porosity of the sand-packed physical models. First, the physical model was placed horizontally and vacuumed over two hours by using a vacuum pump (Fisher Scientific, Maxima plus M16C). After the model was vacuumed, the injection and production control valves were closed tightly. The inlet of the injection valve was submerged into a graduated cylinder which contained the distilled water and the weight of the distilled water was recorded. Then the valve was opened and the distilled water was imbibed into the sand-packed model. After the imbibition process was finished, the weight of the remaining distilled water in the graduated cylinder was recorded. With the weight changes of the distilled water before and after the imbibition and the known density of the distilled water, the volume of the distilled water imbibed into the sand-pack model was calculated and the pore volume of the sand-pack model was determined by subtracting the measured dead volume of the physical model from the total measured volume of water imbibed into the physical model. The porosity of physical model was then determined as the ratio of the pore volume to the bulk volume of the model. The porosities of the sand-packed model in each test were measured to be in the range of ϕ = 34–36% and are listed in Table 1.

Permeability measurement: The distilled water was used as a working medium and injected into the physical model from one side at different flow rate (10, 20, 30, 40, and 50 mL/min). A fluid transfer cylinder was used to contain the distilled water and a syringe pump (TELEDYNE ISCO, 500D) was used to control the injection flow rate at a constant value. The pressure drop through the physical model was measured and recorded by using the high-precision digital pressure transducer. The permeability of the sand-pack model was then determined by applying the Darcy’s Law for steady-state fluid flow. The permeabilities of the physical model for each test are summarized in Table 1.

The initial oil saturation and connate water saturation: After the permeability measurement, the physical model was fully saturated with distilled water. The heavy oil sample, which was contained in another transfer cylinder and controlled by the syringe pump, was then injected into the model from the port on the side at a constant flow rate of q = 0.1 mL/min, so that the gravity would have a limited effect on the saturation process. After the model was saturated with heavy oil sample and no more water was produced, the connate water saturation was obtained by calculating the ratio of the remaining volume of water inside the physical model to the pore volume of the model. The range of the connate water saturation was found to be from S_{wc} = 3–12%. Accordingly, the initial oil saturation was in the range of S_{oi} = 88–97%. The initial oil saturation and connate water saturation are summarized in Table 1.

The residual oil and water saturations

The residual water and oil saturations were measured at different location of the physical model after each test done. More specifically, several oil sand samples were taken from the physical model at different locations. The weight of each sample was measured and then placed into the oven at temperature of 100 °C for over 12 hours to evaporate the residual water. The weight change was noted as the weight of residual water W_{w}. The water-free oil sand sample was then rinsed by kerosene and/or toluene to extract the residual oil until the sands became colorless. The water- and oil-free clean sands sample was then measured as W_{s} and the weight change (the weight of residual oil) was noted as W_{o}. With the known water, oil and sand density ($\rho_{\mathrm{w}}, \rho_{\mathrm{o}}, \rho_{\mathrm{s}}$) and porosity ($\phi$) of the physical model, the residual water and oil saturations were obtained by the following equations:

$$S_{\mathrm{wr}} = \frac{W_{\mathrm{w}}}{W_{\mathrm{s}}}\frac{\rho_{\mathrm{s}}}{\rho_{\mathrm{w}}}\frac{1-\phi}{\phi},$$

$$S_{\mathrm{or}} = \frac{W_{\mathrm{o}}}{W_{\mathrm{s}}}\frac{\rho_{\mathrm{s}}}{\rho_{\mathrm{o}}}\frac{1-\phi}{\phi}.$$

CPCSI tests and 2-D VAPEX test

Tests #1–6 and #8 were performed as 1-D CPCSI and 2-D lateral CPCSI processes. More specifically, the propane was injected into the physical models saturated with heavy oil sample. Solvent injection valve was opened and injection pressure was set as the pre-specified operating condition (P_{inj} = 800 kPa). The solvent was continuously introduced into the physical model. Meantime, the BPR was used to keep the outlet production pressure at a constant operating pressure condition that was about 200–250 kPa lower than the injection pressure until the gas breakthrough occurred, which was observed by using a bubbler. The cumulative oil produced at a different time during this stage was recorded. After that, the BPR was adjusted to the CPCSI operating condition, which was 10 kPa lower than injection pressure. Then shut in the production valve. After that, the production valve was controlled as a cycle of 50-min-close/10-min-open. The cumulative oil production was measured for each cycle. The total amount of solvent used in each test was measured by weight change of the propane cylinder before and after the test.

Test #7 was performed as 2-D lateral VAPEX process. Following the same procedures as described for the CPCSI process before start injecting propane into the physical model. Unlike the CPCSI process, the production pressure was set by the BPR at a pre-specified condition, which was as close as the injection pressure. The bubbler was used to observe the gas breakthrough to make sure that the production pressure was as close as the injection pressure so that the process was dominant by gravity only. Once the test operating conditions were set, the production was started and the produced cumulative oil at different times was recorded.

Results and discussion

Gravity drive in 1-D physical model

A pre-test was conducted to examine the effect of gravity drive in 1-D model by employing an experimental setup, which both injector and producer were located at the bottom of the 93 cm long thin tube model. The gaseous propane was injected into the model through the injector at a constant pressure of P_{inj} = 800 kPa. The production pressure was set by adjusting the BPR to the value close to the injection pressure to avoid possible gas breakthrough so that this process was dominated by gravity only and can simulate the solvent chamber rising phase of VAPEX process. The oil production was extremely low at the first 17 hours. This experimental setup failed to simulate the 1-D rising phase of VAPEX process. In order to speed up oil production, the injector was re-located to the top of the model and the solvent flush production scheme was employed. A greater differential pressure was applied for the next 7 hours. Then the production pressure was set as close as the top injection pressure to avoid a great gas-oil ratio. The solvent flush production period was last about 55 hours. During this period, the oil production rate was stable, and average oil production was found to be at 2.67 g/h. After the total 72 hours production, the process turned to the cyclic production scheme to see if the cyclic production process could improve the performance. The cyclic process was last another 35 hours and it was found that the production increased significantly. The average oil production rate was jumped to 3.91 g/h. The production and pressure data are presented in Figure 3.

Heavy oil production in 1-D CPCSI tests

Figure 4 presents the cumulative oil production versus time data for Tests #1–3, which is a vertical CPCSI production scheme. It obviously indicates that the CPCSI process can be divided into three phases: first one is the phase of build up communication between the injector and the producer; second one is the phase of the production start to increase; and third one is the phase of production start to decline.

In the first phase, a greater pressure difference (ΔP = 200–250 kPa) was applied between the injector and the producer in order to build up the communication. The convective dispersion and diffusion processes were occurred. As shown in Figure 4, when the model length decreased, the solvent breakthrough time became earlier and the communication time took shorter. This is because the same differential pressure was applied in these three tests, so that as the model length went shorter, the pressure gradient became greater. Since the shortest model led to the highest production rate in the first phase, it concludes that the convective dispersion is a more important factor than the diffusion that affects the production rate in this period.

Once the solvent breakthrough occurred, the production pressure was increased by adjusting the BPR to a pre-specified pressure, which was 10 kPa lower than the injection pressure, the CPCSI process turned to the second phase, production start to increase. During this period, the production valve was operated as a cycle of 50-min-close/10-min-open. The production rate increased significantly in this phase. It is worth to mention that when opening the production valve, the foamy oil flow was observed in the early a few minutes (Figure 5), normally less than five minutes. In the next five minutes of production period, a few more oil drops were blew out by the gas flush. After the ten minutes production period, only gaseous propane was produced. It is believed that because the small pressure drop was applied, so that the foamy oil flow was formed inside the model and kept its foamy behavior during the production period. The small pressure drop secured that the oil was in the foamy form and the reduced oil viscosity did not re-increase significantly. The oil saturation in the porous medium substantially increased because of the foamy oil flow, as well as the oil swelling effect. It was noticed that the average oil production rate in this phase was found to be 7.37 g/h, 14.38g/h and 5.01 g/h in Tests #1–3, respectively. The shortest model led to the lowest average production in this phase. It was because of that the same well open/shut-in time was used, and it was too long for the shortest model. The well open/shut-in scenario is an important factor that affects the production in this period.

After certain time of CPCSI process, the production rate started to decline so that the CPCSI process turned to the third phase. It was mainly because the residual oil saturation of the model was low. The average production rate was found to be 1.81 g/h, 2.27 g/h and 1.00 g/h, respectively. Though production could be continued, it was not economical due to the significant oil production rate reduction. It can be seen that the time start to decline versus the model length had a linear relation in Tests #1–3, as shown in Figure 6.

Figure 7 presents cumulative oil production versus time data for Tests #4–6, horizontal CPCSI production scheme. Similar with the vertical placement production scheme, the results showed three phases in horizontal placement production scheme. In Test #6, the gas breakthrough happened very early and the production rate was kept almost constant. It was mainly because of the wall effect, and the gas overriding that was caused by the gravity differentiation. The wall effect affected the performance of horizontal CPCSI process significantly, particularly in the first phase. As shown in Figure 7, the first phase was barely exist in Test #6 because of that the wall effect caused the solvent passed through the wall and reached the producer very quick so that the production was turned to second phase very early. It was also noticed that the production rate was similar with that in the third phases in Tests #4 and #5. In general, wall effect and gas overriding caused that the solvent passed the model and was produced easily. But on the other hand, gas overriding and wall effect enlarged the solvent-oil contact in porous medium during solvent injection/soaking period, and the porous medium was re-saturated by the foamy oil and swelled oil. That might be the reason that in the second phase, the production rates were even slightly higher than those in vertical placement production schemes.

Solvent injection: The total propane that was injected into the model was measured by weighing the total weight changes of the propane cylinder before and after each test, as the data are listed in Table 2. For vertical placement production scheme from Tests #1–3, the total propane used was 349 gram, 218 gram and 157 gram, respectively. For horizontal placement, from Tests #4–6, total propane used was 386 gram, 257 gram and 123 gram, respectively. Considering the solvent-oil-ratio, it clearly shows that 0.8783 gram propane was used for producing 1 gram oil in Test #2, which is the lowest among the three vertical tests. In Test #5, 1.6841 gram propane was used for producing 1 gram oil, which was the lowest among the three horizontal tests. It can be seen that the middle length model led to the lowest SOR among these tests. In another word, the pressure gradient and the well distance are two key factors that affect the CPCSI process.

Residual oil saturations: The residual oil saturations were measured by analyzing the sand samples taken from the model at the end of each test. The residual oil saturation profiles were shown in Figures 8 and 9. The values of the model length for each test were normalized to a dimensionless form. Value 0 represents the location where the injector was located, and value 1 represents the location where the producer was located.

For those vertical placement tests, the residual oil saturation on the top of the model was low. In contrast, at the bottom of the model where the producer was located, the residual oil saturation was higher. This was because the propane that was injected into the model through the top injector was dissolved into the oil and the diluted oil drained downward by gravity, as well as gas flush. The oil was accumulated near the producer during injection/soaking period and then produced in the producer opening period. Hence the oil saturation was higher near the bottom producer rather than that was in any other area inside the model. The oil sand samples were also visually analyzed. It is worth to note that the colours of the most parts of the cross section of the model were not evenly distributed, which indicated that the viscous fingering and the wall effect were significant. Solvent fingering can enlarge the contact area of the solvent and oil, which was helpful on diluting the oil. Wall effect for these tests was controversial. Wall effect can make the gaseous solvent pass through quickly in production period. But on the other hand, during the injection and soaking period, the diluted oil could be swelled and re-saturated the wall, and drained downward through the wall so that the oil could be easily produced during production period. This may explain why the residual oil saturation was lower at the surrounding area of the inside wall.

For those horizontal placement tests, the residual oil saturations were lower at the top layer of the physical model. In contrast, the residual oil saturations were relatively higher at the bottom layer. The difference between them was not significant near the injector because the gas overriding phenomenon was not severe at that location. As the length increased, the difference became more severe. The gas overriding and wall effect made the gas pass through the top layer of the model easily so that the solvent-oil contact area was even larger than that in vertical placement scheme. In addition, the top layer was easily re-saturated with the foamy and swelled oil so that it could be produced in the production period. However, once certain amount oil on the top layer was produced, no more sufficient foamy and swelled oil to re-saturate the top layer porous medium, so that the production started to decline quickly.

Vertical and horizontal production schemes

As discussed above, the ultimate oil productions in vertical production scheme were significantly greater than those in horizontal production scheme. More specifically, horizontal placement led to an early breakthrough during first phase and the production turned to the second phase quickly. In addition, the highest production rate of second phase last shorter and production turned to the third phase early. It is also worth to notice that the middle length model generated the highest average production rate among each own group. This is because the constant pressure drop between the injector and the producer was employed and different model length led to different pressure gradient, so there was an optimal pressure gradient for the specific applications.

Solvent trap: In the SAGD process, a concept of steam trap was developed to control the steam short circulation between the injector and the producer. A similar concept, solvent trap, for solvent injection process is developed in this work. In the CPCSI process, the producer shut-in period allows continuous solvent diffusion and the diluted oil continuously draining downward to the producer under the assistance of gravity. The drained oil accumulated around the producer which is always placed at the bottom of the reservoir. Therefore, a liquid zone with diluted oil will be formed above the producer, while the solvent will be trapped in the chamber above this liquid zone. The produced gas saturation and increased oil saturation around the wellbore yielded a higher production once the producer was opened. This can be used to explain why the higher residual oil saturation was observed near the producer, whereas the lower residual oil saturation was observed near the injector.

Important factors in 1-D CPCSI tests

The results of Tests #1–6 indicate that CPCSI process is promising on 1-D thin tube physical models. Because the constant pressure drops were applied for different length models, the well distance and pressure gradient are two key factors that affect the production performance of the CPCSI process. The middle length model led to the relatively higher average production rate q_o in both vertical and horizontal placement production schemes. The greater pressure drop between the injector and the producer cannot improve the production performance, whereas, it can substantially increase the solvent oil ratio that may make this process less economical (Jiang et al. 2012). In comparison with the results of vertical placement production scheme, the production of horizontal placement scheme decreased significantly by neglecting the gravity drainage. Gravity still plays important role in solvent injection/soaking period. In addition, injection/soaking and production time is another factor that affect the performance of CPCSI process. Longer injection/soaking time is helpful for diluting oil and re-saturated the porous medium effectively. However, it may not be beneficial for average production rate. The results also indicate that production period should be kept short in order to avoid great amount solvent production in the late time of the production period.

Applicability of CPCSI process for 2-D physical model

2-D lateral CPCSI test and 2-D lateral VAPEX test were performed to evaluate the potential applicability of CPCSI process on scale-up 2-D model. Figure 10 presents the cumulative oil production data for 2-D lateral VAPEX and 2-D lateral CPCSI tests. It can be seen that the ultimate cumulative oil production were close but it took about 24 hours more to achieve so in lateral VAPEX test. At the time of 56 hours, the oil recovery factors for two tests were 43.11% and 54.87%, respectively. The oil recovery increment was 11.76% from VAPEX test to CPCSI test. The average oil production rate in lateral CPCSI test was significantly higher than that in lateral VAPEX test. The digital photographs of residual oil saturation distributions of 2-D models taken at the ends of Tests #7 and #8 are shown in Figure 11. It can be seen that the solvent chamber boundary and the untouched oil zone moved downward further more in Test #8 than that in Test #7. This means that the foamy oil and partial diluted heavy oil are produced in CPCSI process, which is different than VAPEX process that only the diluted oil will be produced by the gravity. It is also worth to note that the colour of solvent chamber of the VAPEX test appears evenly light. In the CPCSI test, a few diluted oil fronts were existed in the solvent chamber. This was occurred mainly because of two reasons. One was the interface of the liquid zone with diluted oil and the solvent chamber that was formed due to the solvent trap mechanism, which was discussed earlier, the diluted oil was accumulated near the producer. Another one was because during the production period, where a pressure drop was applied, the oil was swelled and foamy oil was formed which caused the saturation front move. Hence that part of the oil was very easy to be flushed out during the production period.

Conclusions

In this study, 1-D CPCSI tests, 2-D VAPEX and 2-D CPCSI tests were performed to evaluate the new enhanced solvent injection technique for enhanced heavy oil recovery. It was found that cyclic production with continuous solvent injection process can substantially improve the heavy oil recovery performance. The average heavy oil production rate was higher than that in VAPEX process. The small pressure drop in the production period caused the foamy oil flow. In conjunction with the oil swelling, the diluted oil re-saturated the porous medium and then produced easily by the continuous gas flush. The wall effect in CPCSI process less affected the heavy oil production because it provided extra paths for the solvent to dilute the oil in solvent injection/soaking period. Solvent trap mechanism was evaluated and it was found that solvent trap can substantially improve the production performance during the cyclic production period. Well configuration, well distance, and shut-in/open scenarios are the key factors for implementing this method successfully.

The future works: The optimal shut-in/open scenarios will be evaluated based on various well configurations and distances in scaled up physical models. Because the continuous solvent injection in cyclic production period is for maintaining the reservoir pressure and offering gas flood, so that a substitute gas, such as methane or CO_2, can be used in the CPCSI cyclic production period in order to reduce the costly solvent injection. The performance need to be evaluated in comparison with the traditional solvent mixture injection process.

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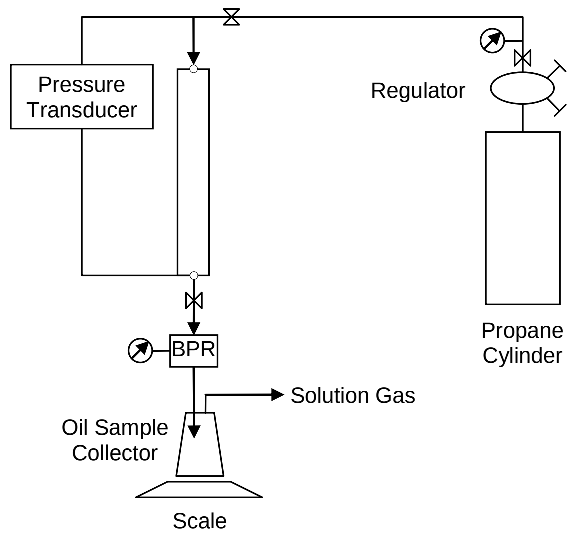
Table 1: Physical model properties and experimental conditions

Test	Production scheme	T (°C)	P_{inj} (kPa)	ϕ (%)	k (D)	S_{oi} (%)	PV (mL)
#1	Vert. CPCSI	21	~800	35.46	4.50	88.24	374
#2	Vert. CPCSI	21	~800	35.47	4.23	96.61	295
#3	Vert. CPCSI	21	~800	35.79	4.22	96.38	138
#4	Horz. CPCSI	21	~800	35.17	4.20	95.96	371
#5	Horz. CPCSI	21	~800	35.83	4.79	96.48	256
#6	Horz. CPCSI	21	~800	35.66	4.20	94.55	137
#7	2-D VAPEX	21	~800	36.75	5.05	96.60	294
#8	2-D CPCSI	21	~800	36.88	4.75	96.95	295

Table 2: Cumulative oil production data

Test	Production scheme	Q_{sol} (g)	Q_o (g)	SOR (m_{sol}/m_o)	t (h)	RF (%)	q_o (g/h)
#1	Vert. CPCSI	349	273.0	1.2784	67	84.41	4.07
#2	Vert. CPCSI	218	248.2	0.8783	46	88.86	5.40
#3	Vert. CPCSI	157	112.4	1.3968	35	86.23	3.21
#4	Horz. CPCSI	386	220.7	1.7490	67	63.26	3.29
#5	Horz. CPCSI	257	152.6	1.6841	45	63.05	3.39
#6	Horz. CPCSI	123	66.2	1.8580	36	52.15	1.84
#7	2-D VAPEX	/	151.6	/	80	54.47	1.90
#8	2-D CPCSI	/	153.8	/	56	54.87	2.75



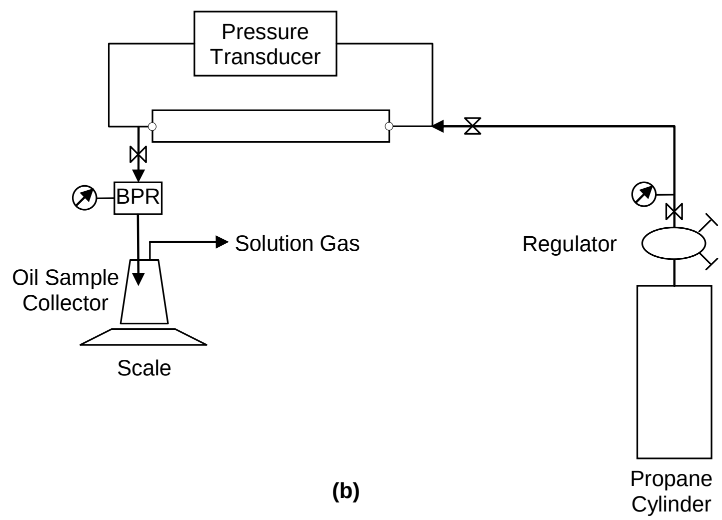


Figure 1: Schematic diagram of 1-D (a) vertical CPCSI and (b) horizontal CPCSI setup

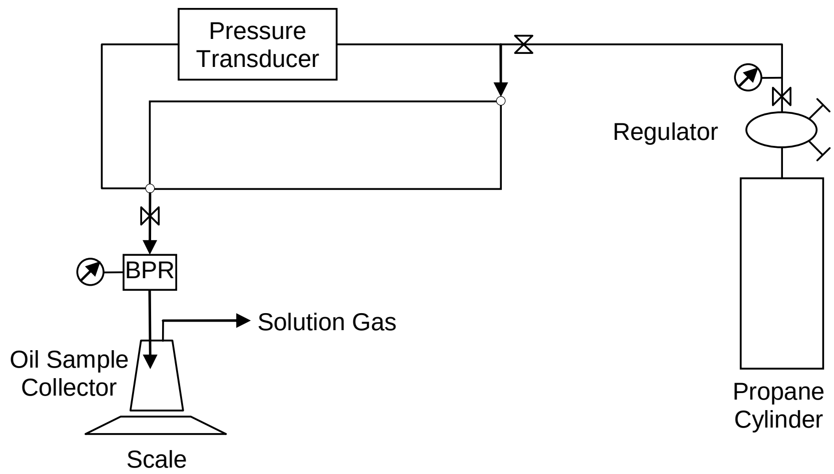


Figure 2: Schematic diagram of 2-D lateral VAPEX/CPCSI setup

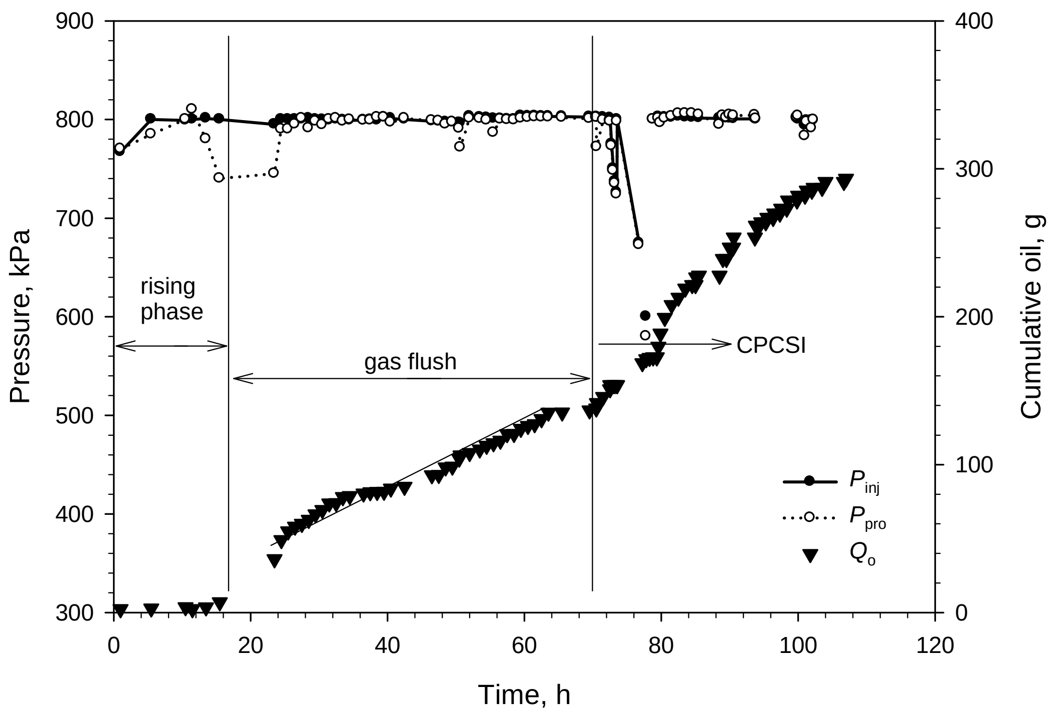


Figure 3: Pressure and cumulative oil production versus time data

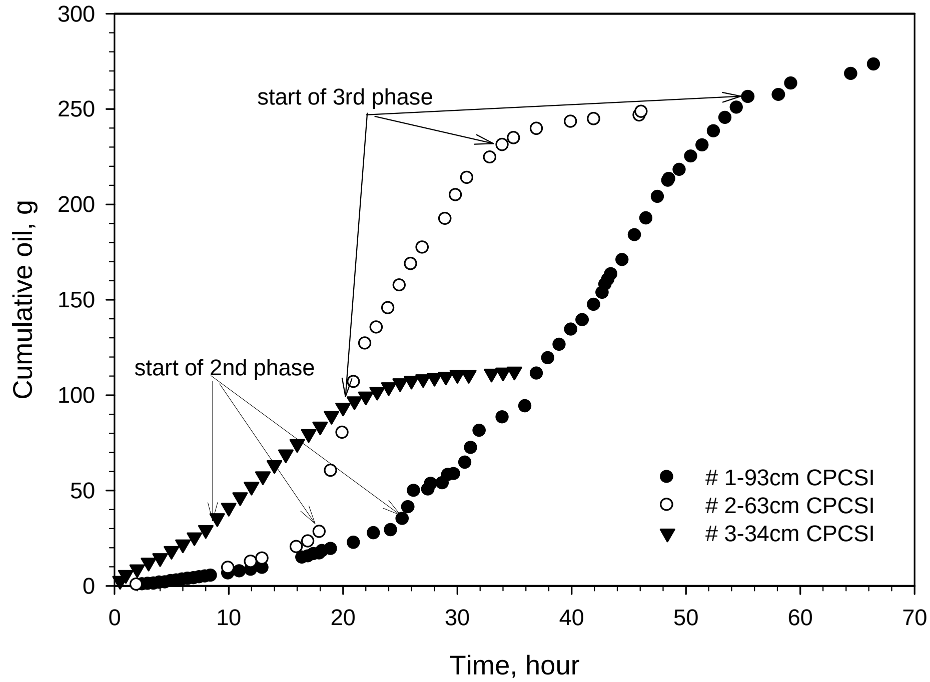


Figure 4: Cumulative oil production versus time data for Tests #1–3, vertical CPCSI scheme

Figure 5: The foamy oil flow was observed in cyclic production period

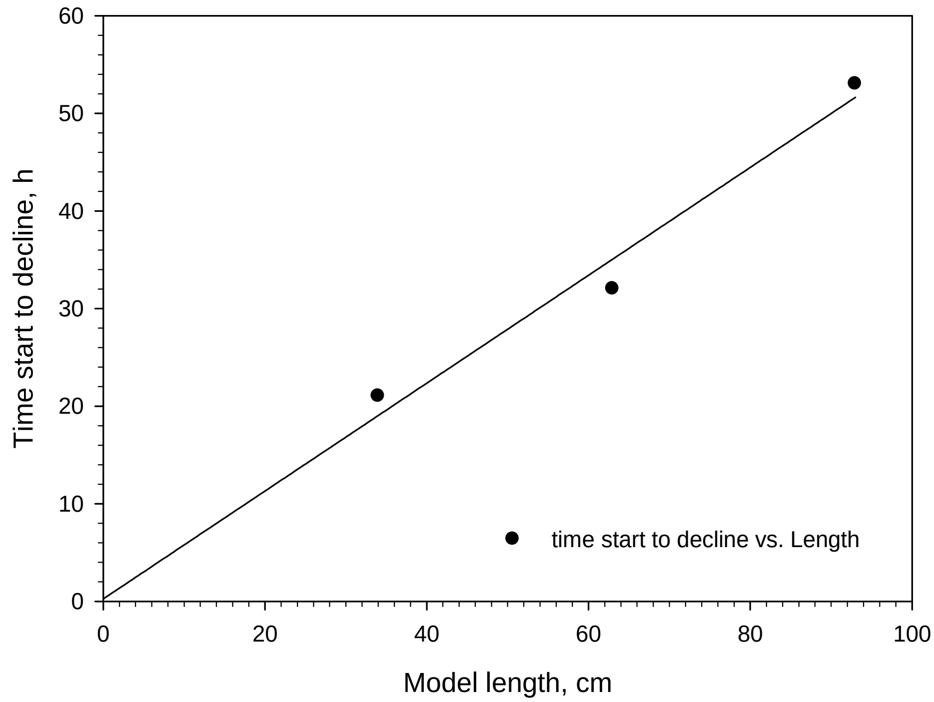


Figure 6 Time start to decline versus model length for vertical production scheme

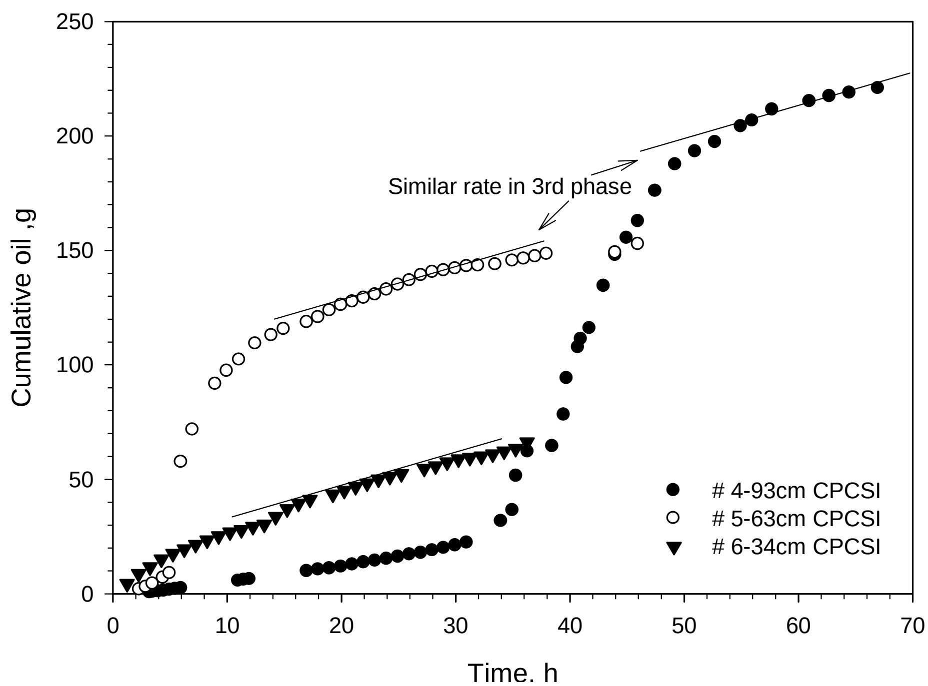


Figure 7: Cumulative oil production versus time data for Tests #4–6, horizontal CPCSI scheme

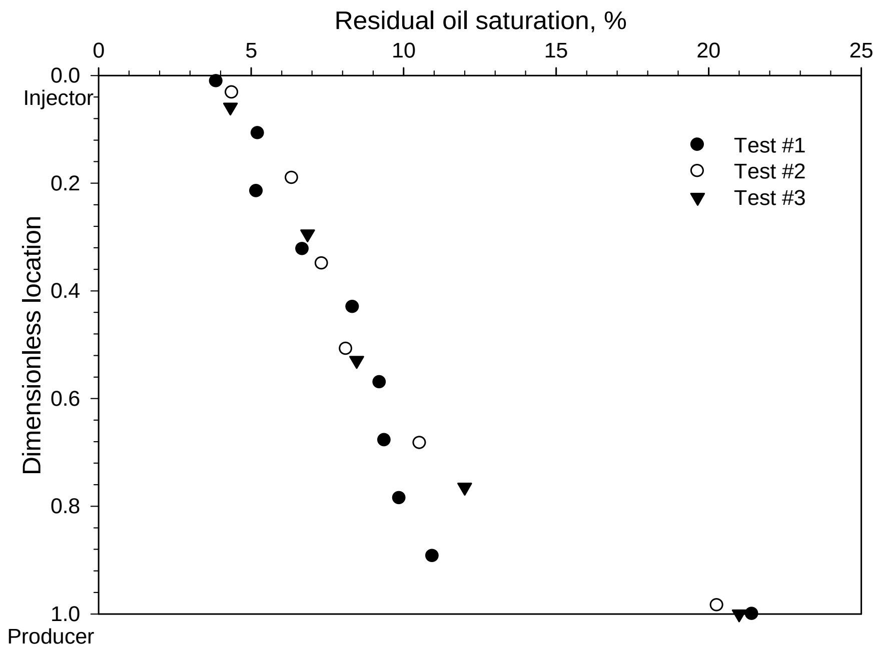


Figure 8 Residual oil saturation distribution profiles of Tests #1–3, vertical production scheme

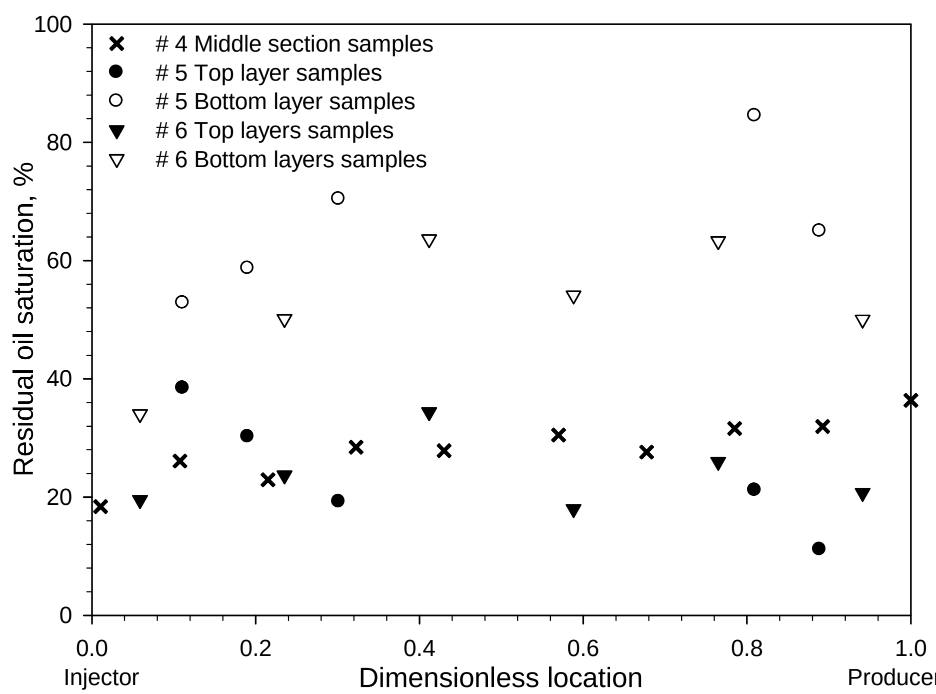


Figure 9 Residual oil saturation distribution profiles of Tests #4–6, horizontal production scheme

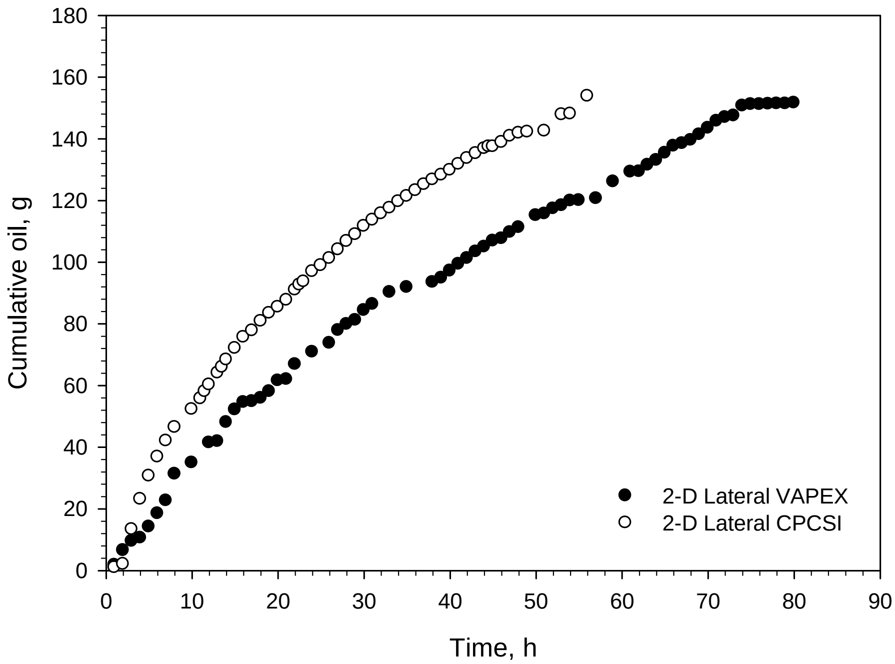
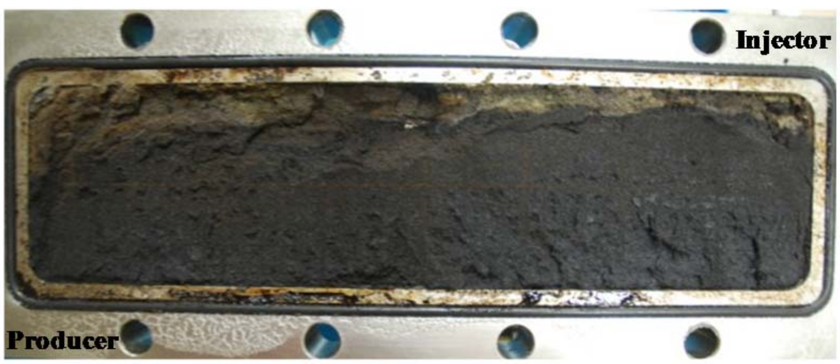


Figure 10 Cumulative oil productions versus time data for Tests #7 and #8



(a)

(b)

Figure 11 Digital photographs of residual oil saturation distributions of physical models taken at the ends of (a) VAPEX Test #7 and (b) CPCSI Test #8