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A Critical Review Using CO_2 and N_2 of Enhanced Heavy-Oil-Recovery Technologies in China

Xujiao He [1], Liangdong Zhao [1], Xinqian Lu [1], Fei Ding [1], Zijian Wang [1], Ruijing Han [1] and Pengcheng Liu [2,*]

[1] Research Institute of Petroleum Exploration and Development, PetroChina, Beijing 100083, China
[2] School of Energy Resources, China University of Geosciences, Beijing 100083, China
* Correspondence: lpc@cugb.edu.cn

Abstract: Thermal recovery technology is generally suitable for shallow lays due to the higher thermal loss for the deep heavy-oil reservoirs. Non-thermal recovery technologies, such as the non-condensate gas injection technology, are not limited by the reservoir depth and could be extensively applied for the heavy-oil reservoir. Many experimental studies and field applications of non-condensate gas injection have been conducted in heavy-oil reservoirs. The injected non-condensate gas could achieve dynamic miscibility with heavy oil through multiple contacts, which has a significant viscosity-reduction effect under the reservoir conditions. In addition, the equipment involved in the gas injection operation is simple. There are many kinds of non-condensate gases, and common types of gases include N_2 and CO_2 due to abundant gas sources and lower prices. Moreover, CO_2 is a greenhouse gas and the injection of CO_2 into the reservoir would have environmental benefits. The non-thermodynamic method is to inject N_2 and CO_2 separately to produce heavy oil based on the mechanism of the volume expansion of crude oil to form elastic flooding and reduce crude oil viscosity and foamy oil flow. Steam injection recovery of the thermodynamics method has the disadvantages of large wellbore heat loss and inter-well steam channeling. The addition of N_2, CO_2, and other non-condensate gases to the steam could greatly improve the thermophysical properties of the injected fluid, and lead to higher expansion performance. After being injected into the reservoir, the viscosity of heavy oil could be effectively reduced, the seepage characteristics of heavy oil would be improved, and the reservoir development effect could be improved. Non-condensate gas injection stimulation technology can not only effectively improve oil recovery, but also help to achieve carbon neutrality, which has a very broad application prospect in the future oil recovery, energy utilization, environmental improvement, and other aspects.

Keywords: heavy-oil reservoir; non-condensable gases; production enhancement; hot fluids; enhanced oil recovery

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1. Introduction

There are about 4 billion tons of onshore heavy-oil resources in China, which reserves more than 20% of the total oil resources in China. At present, more than 70% of heavy-oil fields have been discovered in 12 basins [1,2], including the Liaohe, Shengli, Henan, and Xinjiang Oilfields. Heavy-oil production accounts for about 10% of total crude oil production each year in China. China is the world's fourth-largest producer of heavy oil after the United States, Canada, and Venezuela. Conventional mining methods are difficult to exploit for heavy-oil reservoirs, which generally adopt thermal production or cold production. Thermal production mainly includes steam injection, hot water injection, and the in situ combustion. Cold production mainly includes microbiological recovery, gas injection, oil displacement, etc. The steam injection method accounts for 97% of the total recovery of heavy oil [3]. As shown in Figure 1, it is the main steam injection thermal recovery method. However, the performance of the steam injection method is limited by the heat loss of wellbore, cross-flow between wells, steam overburden, and uneven production of profile. As a result, it is difficult to produce the remaining oil in heavy-oil reservoirs [4]. Therefore, in the face of the increasing water cut and increasing exploitation difficulty in the later stage of reservoir development, the heavy-oil reservoir changed its development mode, and experimental research and field practices of injecting non-condensate gas were carried out [5,6].

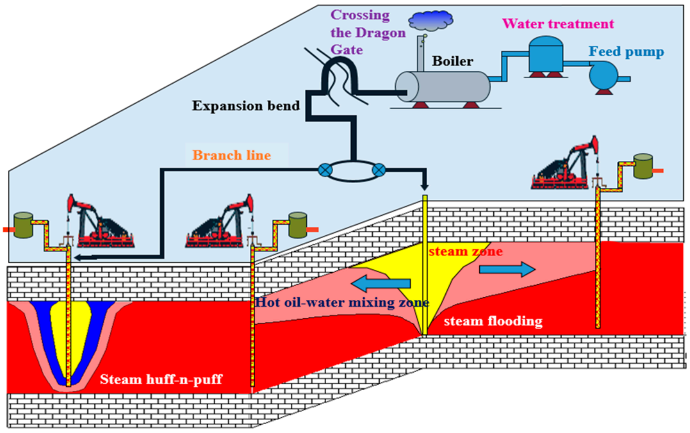

Figure 1. Steam huff and puff and steam flooding.

There are many kinds of non-condensate gases, including CO_2, N_2, CH_4, and flue gas. The main components of flue gas are N_2 and CO_2. CH_4 is not commonly used in petroleum exploitation. Therefore, common types of gases include N_2 and CO_2 due to abundant gas sources and lower prices [7]. Compared with water vapor, N_2 is more readily available due to its high concentration in air, which is conducive to low-cost and efficient development under the situation of low oil price. CO_2 emission in the atmosphere is the main cause of the greenhouse effect. In the application of the non-condensate gas injection technology, CO_2 is injected to the reservoir to enhanced oil recovery and reduce the carbon concentration in the atmosphere through CO_2 storage. The injection of non-condensate gas could reduce the viscosity of heavy oil, increase the volume coefficient of crude oil, and expand the sweep range of waterflooding and the degree of recovery. The injection of N_2 and CO_2 would change the PVT characteristics of the heavy-oil system, such as the viscosity, dissolved gas–oil ratio, bubble point pressure, density, and volume coefficient [8]. As one of the commonly used heavy-oil-recovery technologies, the non-condensate gas injection method has been successfully implemented in some heavy-oil reservoirs, such as the Shengli, Xinjiang, and Bohai Oilfields. It is especially suitable for reservoirs in the late stage of steam injection production, such as steam huff and puff, steam flooding, and SAGD (Steam-Assisted Gravity Drainage) production technology [9]. The non-condensable gas injected in the SAGD production process is SAGP (Steam and Gas Push). Compared with traditional SAGD, adding non-condensable gas can maintain the effective expansion of a mature SAGD steam chamber, which will have higher oil-displacement efficiency. Figure 2, shows the development of a steam cavity after injecting non-condensate gas during the SAGD development of heavy-oil reservoirs. Non-condensate gas injection stimulation technology would not only effectively improve oil recovery, but could also help to achieve carbon neutrality, which has a very broad application prospect in the future oil recovery, energy utilization, environmental improvement, and other aspects. Therefore, this research reviewed the enhanced heavy-oil-recovery technologies using CO_2 and N_2 in China. Both the mechanisms and applications of these enhanced heavy-oil-recovery technologies were reviewed in detail. This work could provide a path forward for future research and be a reference for other heavy-oil production areas.

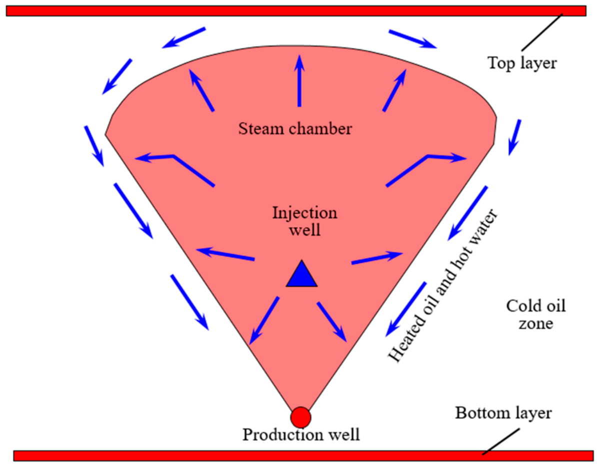

Figure 2. Development process of SAGD steam cavity in heavy-oil reservoir.

2. Adaptability Analysis of Non-Condensate Gas Injection in Heavy-Oil Reservoir

After half a century of research and application, heavy-oil gas-injection-assisted thermal oil-recovery technology has been recognized as one of the feasible and most effective ways [10]. At the beginning, the mechanism of the gas injection to assist thermal oil recovery was recognized as a physical effect. The chemical reaction between high temperature gas and some components of heavy oil has been noticed in recent years, especially the modification effect of non-condensate gas on heavy oil [6]. For a heavy-oil reservoir, there is a challenge to change the development method after a long period of thermal recovery, and the non-condensate gas injection stimulation technology is the most typical and widely used replacement method at present [11].

The study of the remaining oil distribution in a reservoir is of great significance to the adaptability of the subsequent injection of non-condensate gas. Generally, the remaining oil-saturation distribution in the late period of heavy-oil thermal recovery is mainly controlled by reservoir geological conditions and development schemes [12], and the future study of the enhanced oil recovery in the late stage of thermal recovery would mainly focus on increasing the production of the remaining oil. In the process of enhanced oil recovery for the heavy-oil reservoirs, it is very important to select appropriate development methods. However, some production techniques are only suitable for the reservoir types with limited boundaries. The selection of specific development methods is influenced by reservoir properties, economic benefits, and other aspects [13]. The adaptability of a heavy-oil reservoir is generally determined by numerical simulation, among which the increase in recovery efficiency and cumulative oil–gas ratio are the most effective evaluation indexes. Compared with conventional steam development, non-condensate gas injection has a wider adaptability [14].

3. Enhanced Heavy-Oil Recovery by Gas Injection

Thermal oil-recovery technology has been widely studied and applied in heavy-oil reservoirs in Canada, Turkey, and China. However, some heavy-oil reservoirs are thin in formation. When steam injection occurs, the heat loss of the formation is large, and the dryness of the steam decreases rapidly, which leads to the insufficient application of heat. Therefore, in the process of thin heavy-oil reservoir development, the performance of the thermal recovery method to improve heavy-oil production is limited.

The non-thermodynamic methods are widely applied in heavy-oil reservoirs, especially thin and deep reservoirs to reduce the impact of thin and deep reservoir characteristics on low heat utilization efficiency. The non-thermodynamic methods inject solvents into the formation, including methane, ethane, propane, or mixed solvents, and non-condensate gases such as CO_2 and N_2.

3.1. Review of CO_2 Huff-and-Puff Study in Heavy-Oil Reservoirs

Many researchers have conducted experiments of enhanced heavy-oil recovery study using CO_2, and suggest that CO_2 has a significant effect [15–19].

The process of CO_2 huff and puff could be divided into three stages: the injection stage, soaking stage, and production stage [20,21]. The process of CO_2 huff and puff is presented in Figure 3. More detailed processes are as follows: (*a*) oil droplets are pushed to the depth of the reservoir by CO_2, (*b*) the light component is extracted by CO_2, (*c*) CO_2 is dissolved in the heavy components, (*d*) oil droplet expansion, (*e*) Flow direction of liquid, (*f*) residual oil due to changes in rock wettability, (*g*) oil droplets generated by crude oil expansion during production, and (*h*) oil droplets are displaced from the deep formation by the water phase.

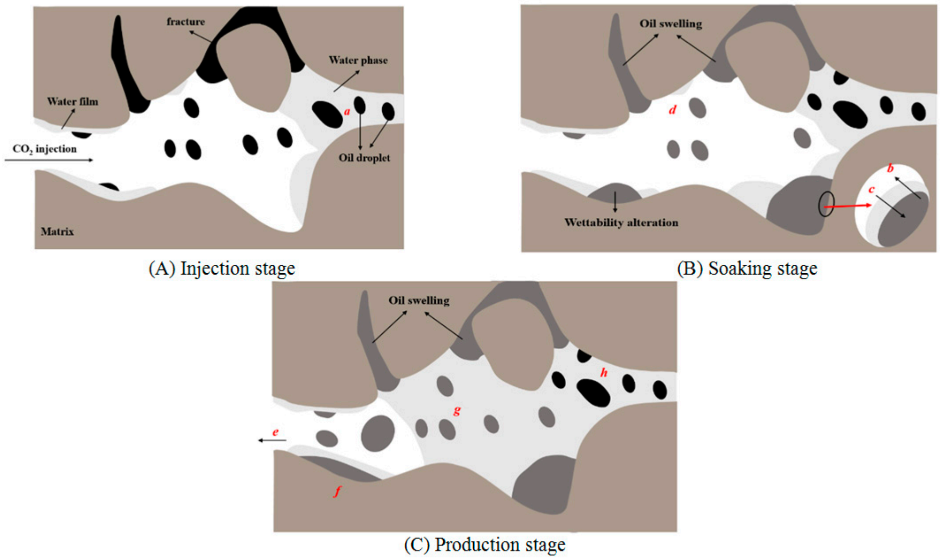

Figure 3. Process of CO_2 huff and puff for a heavy-oil reservoir: (a) oil droplets are pushed to the depth of the reservoir by CO_2; (b) the light component is extracted by CO_2; (c) CO_2 is dissolved in the heavy components; (d) oil droplet expansion; (e) flow direction of liquid; (f) residual oil due to changes in rock wettability; (g) oil droplets generated by crude oil expansion during production; (h) oil droplets are displaced from the deep formation by the water phase.

During the injection stage, CO_2 is injected to the reservoir. As a results, low-viscosity oil and water are pushed by the injected CO_2 to the deep reservoir, and more viscous, non-flowing oil is remained in the reservoir. This results in a significant increase in the heavy-oil relative permeability due to lower water phase saturation in the near-wellbore area, and a higher resistance that prevents the flow of low-viscosity oil mixed with CO_2 into the wellbore. CO_2 diffusion is neglected during the injection stage due to the short time of CO_2 injection, the high injection pressure compared to the reservoir pressure, and the low diffusion coefficient of CO_2 in heavy oil. The injection stage is shown in Figure 3A.

In the soaking stage, the oil production is shut in. The CO_2 diffuses through the formation, causing the oil to expand and reduce viscosity, which is the main enhanced oil-recovery period in the entire huff and puff process. In the meantime, mass transfer occurs between CO_2 and heavy oil, and the light components of crude oil are extracted by CO_2, which increases the volume of crude oil and decreases the viscosity. The soaking stage is shown in Figure 3B.

In the production stage, the CO_2 that is not mixed with crude oil is first produced, then the crude oil mixed with CO_2 is produced in large quantities. Finally, the pressure gradient increases, and the crude oil with higher heavy components is produced through waterflooding. The production stage is shown in Figure 3C.

Generally, laboratory studies are carried out before CO_2 huff-and-puff processes are implemented in the field. These laboratory studies include the experimental study and parameter measurement of the fluid characteristics of a heavy-oil–CO_2 system, such as viscosity, CO_2 solubility, swelling coefficient, interfacial tension, diffusion coefficient, and miscibility pressure. The adaptability of reservoir characteristics such as porosity, permeability, oil saturation, and water saturation is also studied experimentally, and the laboratory-scale optimization of process parameters such as cycle times, injection pressure, and soaking time are also studied [22–24].

Many laboratory studies on enhanced oil recovery using CO_2 for the heavy-oil reservoirs have been conducted by researchers from China, Canada, and the United States. Experimental studies of CO_2 stimulation have been carried out with physical model temperatures up to 90 °C, heavy-oil viscosity up to 28,646 mPa·s, and reservoir permeability ranging from 30×10^{-3} μm^2 (core) to $24{,}200 \times 10^{-3}$ μm^2 (sand-pack model). Lab-scale experimental studies suggest that permeability is not the main parameter affecting CO_2 huff-and-puff productivity in heavy-oil reservoirs. In addition, CO_2 huff and puff could also be applied in reservoirs with low oil saturation (as low as 0.41), which means that CO_2 huff and puff can be performed in reservoirs with higher water saturation [25].

Other scholars have conducted core displacement experiments related to CO_2 huff and puff. The results show that the second cycle would achieve maximum production. Higher injection pressure would result in higher production due to more CO_2 dissolution in heavy oil under higher pressure to reduce the viscosity and increase the oil expansion coefficient. However, the increase in the soaking time does not significantly improve the recovery efficiency. Field injection pressures normally range from 1.7 MPa to 25.0 MPa. In the production stage, the pressure depletion rate has a significant impact on the productivity of heavy-oil reservoirs [26].

For the CO_2 huff-and-puff study using the sand-pack model, the experimental work results suggest that the recovery rate of the CO_2 huff-and-puff process is proportional to the injection pressure, soaking time, and pressure decay rate. CO_2 huff and puff can be used as a follow-up process of primary recovery [27]. In the past few decades, field tests of CO_2 huff and puff for enhanced oil recovery in heavy-oil reservoirs have been successfully applied in many oil fields, as presented in Table 1.

Table 1. Field pilot tests of CO_2 huff and puff for heavy-oil reservoir.

Oilfield Name	Reservoir Depth (m)	Original Reservoir Pressure (MPa)	Porosity (%)	Permeability (mD)	Oi Viscosity (Reservoir Condition) (mPa·s)	Injection Amount (t)	Soaking Time (d)	Performance Evaluation
Bati Raman Oilfield [28]	1310	12.41	14~20	200~2000	2000	1696	/	Oil production increased from 238.5 m^3 to 1113 m^3.
Liaohe Oilfield [29]	1750~1890	17.33	22.8	814	16,300	150	17	The production period is 143 days, oil increment is 820 t, CO_2–oil ratio is 6.47 m^3/t
Jidong Oilfield [30]	1924	14.8	30	602~1622	/	325	21	CO_2–oil ratio of well GP11 and well GP25 is 5.80 during the first cycle and 2.10 during the second cycle.
Dagang Oilfield, Banqiao Region [31]	1900~2400	/	31.1	3077	2598	620	17	Average oil increment is 3.4 times, cumulative oil increment is above 3000 t

The CO_2 huff-and-puff technology was first applied in the forest reserve oil field, and Mohammed conducted research to evaluate the enhanced oil-recovery (EOR) mechanisms associated with CO_2 huff-and-puff applications, such as oil viscosity reduction, volume expansion, and gravity drainage [32]. The related influencing parameters, such as slug size, huff and puff period, CO_2 injection, and reservoir pressure, were also analyzed. Finally, parameters screening criteria for CO_2-EOR were established based on the field test results [33]. The application of CO_2 huff and puff in the Bati Raman heavy-oil reservoir in Turkey is also concerned because of its good recovery effect [34].

In the CO_2-EOR process of this oil field, a series of improved processes, such as a fracture-sealing polymer gel system, chemically enhanced water injection process, and alternate alkaline water gas injection (WAG) process, were used to improve the oil recovery.

These technologies successfully solved the problems of the strong heterogeneity of natural fractured carbonate rocks, the low CO_2/crude oil mobility ratio, and the high gas–oil ratio (GOR) at the late stage of development. Therefore, the immiscible CO_2 injection project is widely recognized as one of the most unique and successful EOR applications in the history of heavy-carbonate reservoir development [35].

In recent years, field applications and field pilot tests of post-thermal CO_2 huff and puff have been conducted in major heavy-oil fields such as the Jidong, Dagang, and Liaohe Oilfields.

In 2005, several CO_2 huff and puff pilot tests were conducted in the Lengjiapu heavy-oil reservoir and Liaohe Oilfield and economic evaluations of the field pilot tests were also implemented. The test results indicate that a higher oil viscosity would result in a higher CO_2 utilization rate, and therefore CO_2 application is more feasible. For extra-heavy oils, 1–3 cycles of steam huff and puff followed by CO_2-EOR, if necessary, could yield good benefits [36]. In 2010, CO_2 injection field pilot tests using a horizontal well were carried out in the Jidong Oilfield, China.

Some production wells achieved an obvious increasing production effect, and the test results show that the effective length of gas injection and oil saturation near a horizontal well bottom hole has a great impact on the CO_2 injection performance, and the CO_2 huff and puff process is better limited to three cycles due to economic evaluation [30]. In 2018, CO_2 injection field pilot tests were implemented in 12 production wells at the Banqiao and Liuguanzhang areas of the Dagang Oilfield. These areas have a high water cut in the late development stage, and the CO_2 injection has an obvious inhibition on water channeling, which would greatly reduce viscosity and increase oil production [32].

Many scholars also carried out numerical simulation research on the CO_2 huff-andpuff process for heavy-oil reservoirs, analyzed production characteristics, and optimized process parameters [37–39]. The numerical study and analysis suggest that CO_2 huff and puff could successfully improve the production of heavy-oil reservoirs. The diffusion area has a significant impact on productivity since the CO_2 huff-and-puff process can only affect the reservoir properties and fluid properties in the near-well area. When the affected area increases to a certain size, the oil increase will remain stable. The soaking time, injection rate, and CO_2 phase state would affect the productivity because they affect the affected area of huff and puff. Crude oil viscosity is the main factor during the CO_2 huff—and-puff process. For crude oil with viscosity of 10,000 to 50,000 mPa·s, one to two cycles would achieve the highest performance, while, for crude oil with viscosity of 100 to 10,000 mPa·s, the process can be extended to three cycles.

3.2. Review of N_2 Injection Study in Heavy-Oil Reservoirs

At present, most reservoirs are developed by waterflooding, and facing the problem of high water cut at the late stage of reservoir development [40]. These types of reservoirs are usually characterized by complex residual oil distribution and rapid increase in water cut, which will affect water injection development performance. It is difficult to maintain effective development through waterflooding. Hence, gas injection has been applied in low permeability reservoirs, fracture-vuggy carbonate reservoirs, tight reservoirs, heavy-oil reservoirs, and fault-block reservoirs instead of waterflooding [41–44].

As early as the 1970s, numerous laboratory and field pilot tests of N_2 injection to enhanced oil recovery were conducted in the United States and Canada [45]. In cooperation with TOTAL of France, the Yanling Oilfield of China has been conducting feasibility technical demonstrations of enhanced oil recovery in the late stage of carbonate reservoir development since 1986. In 1994, the first field pilot test of N_2 injection flooding was conducted, and a certain stimulation effect was achieved. After N_2 injection in the north area of Yanling Oilfield, the oil–water interface decreased, the comprehensive water cut decreased, and the output increased. The annual oil production for nine consecutive years was higher than that before N_2 injection. In addition, the general trend of gas flooding development is to replace hydrocarbon gas with non-hydrocarbon gas. The application of N_2 in oil and gas development is mainly reflected in the following two aspects: (1) N_2 or mixture of N_2 and other gases injection to enhanced oil recovery mainly contributed to the mechanism of increase formation pressure. Since the thermodynamic characteristics of N_2 are not considered, it is considered as non-thermodynamic enhanced oil recovery [46]; (2) N_2 is injected with steam or viscosity reducer, or N_2 is injected in the annulus to reduce heat loss with the consideration of the low thermal conductivity of N_2, and it is considered as thermodynamic enhanced oil recovery [47].

Wang Jiahuai et al. [48] proposed N_2 injection technology to be applied in the late stage of the steam huff-and-puff process in 2002 and conducted field pilot tests in the Karamay 96th Area. The research shows that N_2 injection can effectively improve the development performance in the late steam huff-and-puff process, and can be applied to all stages of the heavy-oil steam huff-and-puff process.

In 2002, Yang Yuanliang [49] studied the technology of N_2-controlled bottom water coning and hot N_2 mixed injection to improve the thermal recovery of a heavy-oil reservoir in Shanjiasi. The results show that N_2 injection can effectively control the bottom water coning after multiple cycles of the huff-and-puff process and improve the thermal recovery efficiency in the heavy-oil reservoir with high bottom water thickness.

For karst cave carbonate reservoirs in Northwest China, Li Jinyi et al. [50] demonstrated the feasibility of N_2 injection in 2008, and Guo Xiudong et al. [51] conducted a test by using N_2 injection to displace high-position oil in 2013. The test results suggest that N_2 will migrate to the high position under the gravity effect, and forms a secondary gas cap to displace crude oil downward. At the same time, the formation energy is restored and the attenuation of the formation energy is slowed, which would effectively control the bottom water coning, and enable the oil that cannot be driven by waterflooding.

In addition, N_2 flooding pilot tests have been conducted in some heavy-oil reservoirs. In 1996, an injection rate of 600 m^3/h and injection pressure of 10.0 MPa were applied to wells Shan 2–3 and Shan 8–16 in the Shengli Shan Jiasi heavy-oil reservoir. Compared with the production index in the last cycle, the lowest water cut in the last cycle decreased by 8.5%, and the oil–gas ratio increased from 0.3 to 0.54. The oil increasing effect was obvious, and significant economic benefits were obtained [38].

Tahe Oilfield conducted a N_2 injection pilot test on TK404 in 2012, and the well was opened in early April of that year. The initial daily liquid production was 49.5 t, the daily oil production was 38.6 t, and the water cut was 22% [52]. In August 2012, well T416 was tested for gas injection, and the test was successful. A total liquid nitrogen of 1503 m^3 and oilfield water of 896.7 m^3 were injected in the test, with 17 t of oil production per day [53].

The comprehensive water cut in the LuKeQin deep heavy-oil reservoir has reached 71% in the past ten years of conventional waterflooding development. Liu Quanzhou [54] determined the optimum gas injection parameters to successfully enhance oil recovery by a laboratory test of N_2 injection, including the foam oil formation by N_2 to improve the oil mobility, block the large pore throat, maintain reservoir pressure, and help drainage. Since the production of block 612, the formation energy has decreased with the increase of huff-and-puff cycles, and the development performance was not satisfying. Wang Chuanfei et al. studied the synergistic effect of nitrogen and viscosity reducer in light of the characteristics of the high viscosity and relatively thin thickness of crude oil in shallow reservoir 1 of Chunhui Oilfield. The results show that this technology can effectively expand the spread range of the steam chamber, greatly improve the spread range of the steam-carrying function to reduce the viscosity, and effectively improve the development effect [55].

4. Non-Condensate-Gas-Assisted Steam Drive

Heavy-oil gas injection to assist thermal recovery injects high-temperature non-hydro carbon gases, including CO_2, N_2, air, and flue gas. The thermal energy carried by high-temperature non-hydrocarbon gas is used to heat heavy-oil reservoirs, reduce the heavy-oil viscosity, and therefore reduce the heavy-oil flow resistance to enhanced heavy-oil recovery [56].

4.1. CO_2-Injection-Assisted Steam Flooding for Heavy-Oil Reservoir

The performance of steam huff and puff and steam drive in the reservoir development is limited by steam overlap and steam channeling due to the heterogeneity of formation, and the differences between the steam and oil density and viscosity. This would result in a decrease in sweep efficiency for steam flooding and a low heat-utilization rate, and eventually cause low oil recovery. For these kinds of reservoir, there is only a 30~50% recovery degree, and more than half of the reserves remain untapped. The application of air, N_2, CO_2, flue gas [57], and other non-condensate gases to assist steam flooding can achieve the purpose of further enhanced oil recovery. Among many non-condensate gases, CO_2 has the most obvious viscosity-reduction effect. In recent years, due to the greenhouse effect on global warming and the more severe environment problems, it is necessary to find a feasible way to reduce CO_2 emission. Many researchers have suggested that, through the integration of CO_2 capture, storage, and oil displacement, the circular economy model can be realized [58,59]. The application of CO_2-injection-assisted steam flooding for heavy-oil reservoirs not only helps solve the problems of rapid production decline for the heavy-oil reservoir, but also greatly reduces the production costs. Therefore, a lot of scholars have conducted studies on the mechanism of CO_2-assisted steam flooding and the optimization of the injection parameters [60].

Many scholars have analyzed the influencing factors of CO_2 injection, such as the injection timing, amount, and mode [61]. CO_2-assisted steam flooding experiment results show that CO_2-assisted steam flooding is better than conventional flooding in both vertical and horizontal wells, and the recovery efficiency increases more than 20%. The optimum injection mount is critical to the ultimate oil recovery. Therefore, it is necessary to conduct research to evaluate the optimal CO_2 injection amount [62]. The optimum study results suggest that the optimal CO_2–steam ratio under a one-dimensional condition is 9.4, and the optimal CO_2–steam ratio under a three-dimensional condition is 8.7. Experiment results show that a 0.5 PV CO_2 injection after steam injection would obtain the best effect [63]. Many scholars have also summarized and analyzed the oil-displacement mechanism in the process of CO_2-assisted steam flooding [64–66]. CO_2 can significantly reduce the heavy-oil viscosity. CO_2 can extract light hydrocarbon components from ultra-heavy oil. CO_2 can replenish formation capacity. CO_2 has a demulsification effect. CO_2 can increase the elastic energy of crude oil. CO_2 can also reduce interfacial tension and residual oil saturation.

As early as 1988, the Midway-Sunset field in California, USA, had conducted a pilot test to study the feasibility of a new steam–CO_2 injection technology. After two stages of testing, it was found that the cumulative oil production increased by 2.08 times and 0.44 times in nine months after three months of development in the new steam–CO_2 injection process compared with steam flooding alone [67]. The CO_2- and surfactant-assisted steam flooding was implemented in the QI 40 block of the Liaohe Oilfield in 2011 [68]. Through an optimization study, the simultaneous injection of steam and CO_2 not only strengthened the viscosity reduction and thermal expansion of crude oil, but also maintained the dryness of steam, improved the heat-transfer efficiency of steam, and made up for the adverse effect of steam condensation in cold oil flooding. CO_2- and surfactant-assisted steam flooding was implanted with an effective rate of 90% and an average oil production increase of 458 t per well.

Compared with pure steam flooding, steam-assisted flooding could save up to 45% steam, and the oil production well would quick respond to the stimulation treatment, which would result in a significant economic benefit. A pilot test of CO_2-assisted steam huff and puff in the Xinglongtai formation of the Du 84 block in the Liaohe Oilfield has been conducted since 2014. There are obvious formation energy-increasing effects. The steam injection pressure is increased from 6.2 MPa to 8.7 MPa. The periodic oil production is increased by 1584 t, and the oil–gas ratio is doubled. The oil-production degree is increased by 26%, and the development effect is greatly improved [69]. Field applications of CO_2-assisted steam flooding are summarized in the Table 2.

Table 2. Field applications of CO_2-assisted steam flooding.

Oilfield Name	Formation Type	Formation Depth	Original Reservoir Pressure (MPa)	Porosity (%)	Permeability (mD)	Oil Viscosity (Reservoir Condition) (mPa·s)	Performance Evaluation
Midway-Sunset Oilfield [67]	Sandstone	52.4	0.33	36	3900	5000~8000	After CO_2-assisted steam flooding, oil production increased by 2.08 times
Liaohe Oilfield QI 40 Block [68]	Sandstone	850	/	32	2062	2639	CO_2- and surfactant-assisted steam flooding, oil incremental 458 t oil per well
Chunguang Oilfield [70]	Conglomeratic sandstone	900~1200	13.6	28	921	30,000~80,000 (50 °C)	The displacement efficiency of CO_2-assisted steam flooding is 11.55% higher than that of simple steam flooding
Liaohe Oilfield Du 84 Block [69]	Sandstone	740~850	8	/	/	168,100 (50 °C)	CO_2-assisted steam huff and puff recovery increased by 5%
Zhuangxi 139 Block [71]	Fine sandstone	1551~1650	13.41	34	1804	2727~9196	CO_2-assisted steam huff and puff cumulatively produced oil 10 × 10^4 t

4.2. N_2-Injection-Assisted Steam Flooding for Heavy-Oil Reservoir

N_2-assisted steam flooding technologies have been widely applied for heavy-oil reservoirs. Compared with steam, N_2 will not condense into water at low temperatures, nor dissolve in crude oil under a certain pressure like CO_2. It is a non-condensing, non-toxic, and harmless inert gas, and pressure has little influence on the characteristics of N_2.

With the rapid development of N_2-production technology, the costs of N_2 are reduced since the N_2 sources are not limited. Therefore, it is possible to apply the N_2-assisted steam flooding technology to field-scale applications. The research shows that, during the steam injection period, N_2 injection can reduce the amount of steam injection, so as to reduce the water content in the well, slow down the bottom water coning, and increase the sweep range of the steam in the formation [72]. In recent years, field applications and laboratory experiments have shown that N_2-assisted heavy-oil thermal technology can improve the development effect of heavy-oil reservoirs, as presented in Table 3.

Table 3. Field application of N_2-assisted steam flooding.

Oilfield Name	Permeability (mD)	Oil Viscosity (mPa·s)	Reservoir Temperature (°C)	Reservoir Pressure (Mpa)	Performance Evaluation
Shengli Lean Oilfield [73]	1647	902~3500 (surface condition)	60	8.6	Experiment with 29 wells, oil increased 22,834 t and average oil gas ratio increased by 0.30
LuKeQin Oilfield [74]	50~700	9569~20,150 (50 °C @ surface condition)	97~103	31~36	After 7 d of well soak with nitrogen injection, the oil production increases from 3.8 t to 7.8 t after nitrogen injection, and the daily oil production is 5.7 t after stabilization.
Xinqian 9 Block [75]		48,847 (50 °C @ surface condition)	-	<3	N_2 injection can prolong the production cycle of a single well, effectively improving the well utilization rate and production time rate
Shengli Bamianhe Oilfield [76]	20~400	5000 (surface condition)	-	10	Compared with steam stimulation, the periodic oil production and water recovery rate are significantly increased, and the periodic steam injection amount is reduced
Chunfeng Pai 601 Block [77]	2500~3900	50,000~90,000	28	2~6	54 horizontal wells have been put into production. The average oil-production capacity of a single well is 8.2 t/d, the cumulative oil steam ratio is 0.48 t/t, and the average peak oil production of a single well is 32 t/d.

The application of N_2-assisted heavy-oil thermal technology has gradually become the main research direction of heavy-oil recovery to reduce the cost of heavy-oil recovery and improve the effect of heavy-oil recovery. However, the performance of N_2-assisted steam flooding is limited due to the cold damage of steam injection, and heated N_2-assisted steam injection could be used to improve the development performance to compensate for this disadvantage.

Since 1970, the United States and Canada have performed N_2-assisted experiments and achieved a series of results [78]. Since 1989, China has carried out experimental research on the use of N_2 to improve the steam-injection effect of heavy-oil reservoirs, and achieved good development results in typical blocks such as the Liaohe, Shengli, and Xinjiang Oilfields [72]. The mixed injection of N_2 and steam can strengthen steam distillation, and nitrogen can reduce the vaporization pressure, so that the steam can maintain a higher temperature and dryness for a longer time. N_2-assisted measures can concentrate on the establishment of temperature field, and expand the steam sweep volume. The dissolved N_2 in the formation forms tiny bubbles, which block the dead pore throat, and therefore greatly improve the use of thermal energy [79]. However, N_2 has little effect on the heavy-oil viscosity, and the steam effect is still the main effect after N_2 injection [80–82].

In 2012, Zhang et al. [83], through the field pilot test of N_2-assisted steam flooding in 9 Block of Xinjiang Oilfield, pointed out that N_2-assisted steam flooding can better maintain and improve the production pressure of oil wells in the huff-and-puff production process. The N_2-assisted steam flooding would supplement the formation energy, prolonging its oil production period. At the same time, part of N_2 will dissolve in the crude oil, sealing the low oil saturation area, and improving the oil-displacement energy to a certain extent at the micro level. Some scholars have reported that the recovery effect becomes worse after multiple cycles of stimulation [84]. They have studied the field pilot tests of N_2-assisted steam flooding to increase the oil recovery. N_2 has a large compression coefficient, which can greatly improve the elastic energy of the formation.

5. Mechanism Analysis of Heavy-Oil Recovery by Injecting Non-Condensate Gas

5.1. Mechanism Analysis of Heavy-Oil Recovery by Gas Injection

Many scholars have studied the main mechanism of non-condensate gas enhanced oil recovery in heavy-oil reservoirs, including the foam oil formation, crude oil viscosity reduction, crude oil volume expansion, interfacial tension reduction, water phase wettability increase, and influence of three-phase relative permeability [85–88]. In heavy-oil reservoirs, it is difficult for the injected CO_2 and N_2 to miscible with crude oil because of the very low minimum miscible pressure (MMP) of non-condensate gas and heavy oil. In addition, the interfacial tension between non-condensate gas and crude oil does not decrease significantly. Since this process is an immiscible process, the main mechanisms can be summarized as oil expansion, viscosity reduction, and formation energy replenishment [89]. The main mechanism of non-condensate gas to enhance oil recovery in heavy-oil reservoirs can be summarized as follows:

(1) **Crude oil volume expansion.** Non-condensate gases such as CO_2 and N_2 dissolve in crude oil and expand the volume of crude oil. Compared with other gases such as N_2, CO_2 has a larger expansion coefficient of crude oil. The volume expansion of crude oil can not only improve the formation elastic energy, but also make the expanded crude oil free from the constraints of rock and formation water, thus increasing the oil production [88]. At the same time, gas dissolution expands the volume of crude oil, and the expanded oil pushes water out of the pore space, so that the drainage oil-phase relative permeability is higher than the imbibition water-phase relative permeability, and the relative permeability transformation occurs, which is conducive to the flow environment of oil flow.

(2) **Crude oil viscosity reduction**. There is significant crude oil viscosity reduction after the dissolution of CO_2 and N_2. Laboratory experiment results show that the crude oil viscosity decreases with the continuous dissolution of CO_2. There is greater crude

oil viscosity reduction after CO_2 dissolution when the original crude oil viscosity is higher. The viscosity of crude oil can be reduced to about one tenth of the original value; that is, the viscosity-reduction range can reach 90%. Reducing the viscosity of the oil phase increases the oil mobility, making it easier to flow through the wellbore. At the same time, it also reduces the remaining oil saturation, thereby increasing production per well [7,8].

(3) **Component extraction**. Non-condensate gas can evaporate and extract crude oil. When the injected gas contacts the oil in the reservoir, the hydrocarbons in the oil will evaporate due to the component extraction. The gas phase will be enriched continuously. The injected gas is more likely to miscible with crude oil and improve the oil displacement efficiency [90].

(4) **Formation energy replenishment**. Gas injection can effectively replenish formation energy and maintain reservoir pressure, and N_2 has good displacement property, gas lift, and drainage functions due to its good expansibility. N_2 can enter the low-permeability formation and small pores where water finds it difficult to enter. The residual oil left in the reservoir after waterflooding can be displaced from the small pores. In addition, the purpose of maintaining formation pressure by gas injection is to keep the condensate reservoir pressure above the dew point pressure, so as to avoid the reverse condensate phenomenon below the dew-point pressure and reduce condensate and crude oil recovery [91].

5.2. Mechanism Analysis of Heavy-Oil Recovery by Non-Condensate Gas Injection

The main stimulation mechanisms of conventional steam flooding are viscosity reduction, thermal expansion, steam distillation, and oil-phase permeability improvement. Non-condensate-gas-assisted steam injection to develop heavy-oil reservoirs not only has a steam flooding mechanism, but also has the following flooding mechanisms:

(1) **Insulate and reduce heat loss**. The density of CO_2 is less than the density of steam [92]. N_2 has a low thermal conductivity. Hence, both gases provide excellent heat insulation. Therefore, injecting a certain amount of non-condensate gas during steam injection can act as a heat insulation in the oil casing annulus and reduce heat loss in the wellbore. Non-condensate gas will preferentially occupy the top space of the reservoir to form the overlying phenomenon, so that the steam heats the cold oil area of the stratum, slows down the steam overlying effect, expands the steam sweep range, and improves the heat utilization [93]. Figures 4 and 5 show the temperature field distribution after N_2 injection into formation [94]. Figure 4A shows that the steam chamber extends from the injection well to the production well, Figure 4B shows that the steam chamber mainly expands in the horizontal direction, and Figure 4C shows that the thermal front reaches the production well. Figure 5A shows the expansion of the thermal front, Figure 5B shows the promotion of fluid override, and Figure 5C shows the occurrence of fluid channeling.

(2) **Demulsification and interfacial tension reduction**. It is easy to cause high-temperature emulsification in the process of steam injection for heavy-oil and ultra-heavy oil, forming water-in-oil emulsion, which greatly increases the viscosity of crude oil and reduces the fluidity of crude oil. However, the non-condensate gas has a high diffusion coefficient in oil and water. Its diffusion effect can redistribute the gas itself and destroy the water-in-oil emulsion formed by steam injection, stabilize the phase equilibrium of the system, and further reduce the tension at the oil–water interface. In addition, due to the high solubility of CO_2 in crude oil, adding CO_2 to steam can increase the affinity of oil and water, and improve the interfacial activity. It can also break the oil film adsorbed on the rock surface into small movable oil droplets, and greatly reduce the interfacial tension of oil and water [95].

(3) **Increase formation pressure and replenish formation energy**. A certain amount of nitrogen can effectively replenish the formation energy and maintain the pressure during steam injection, thus prolonging the huff-and-puff period and increasing the

average pressure drop [92]. The mixed injection of hot steam and CO_2 makes full use of the characteristics of large elastic energy in gas flooding, which can make up for the pressure reduced by steam condensation, so as to maintain the formation pressure. At the same time, CO_2, as a non-condensate gas, can continuously replenish the formation energy, improve the formation pressure, and accelerate the flowback rate of fluid in the process of the end of the soaking well [96]. Figure 6 shows the SAGP technology of a heavy-oil reservoir [97].

(4) **Help to remove blockage and increase seepage capacity**. N_2 has good displacement property, gas lift, and drainage functions due to its good expansibility. CO_2 is weakly acidic when dissolved in water, which becomes more acidic at high temperature. It reacts with the formation matrix, and acid decomposes some impurities, and removes the pollution near the well zone. In addition, it can also dissolve the mineral components such as calcite and dolomite in the rock, thus enlarging the pores between mineral particles and enhancing the seepage ability of the rock [98]. After the non-condensate gas is injected into the formation, the process of dissolving the rock and increasing the seepage space is shown in Figure 7.

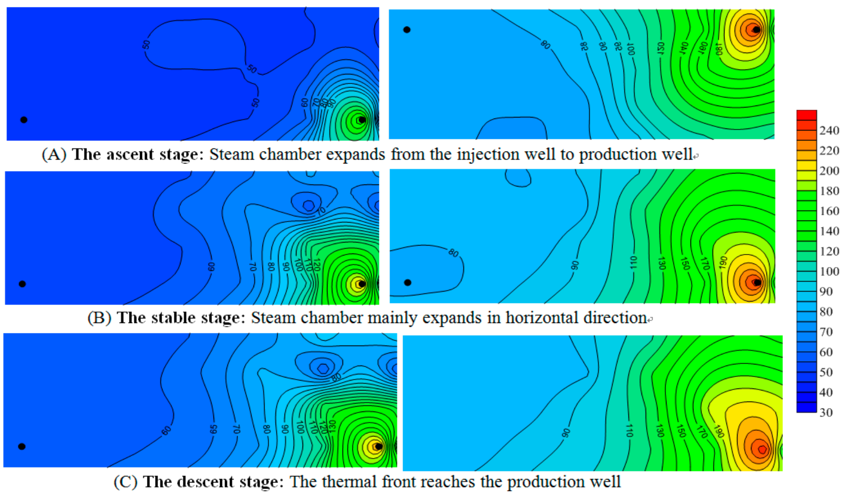

Figure 4. Nitrogen-assisted steam temperature field distribution [94].

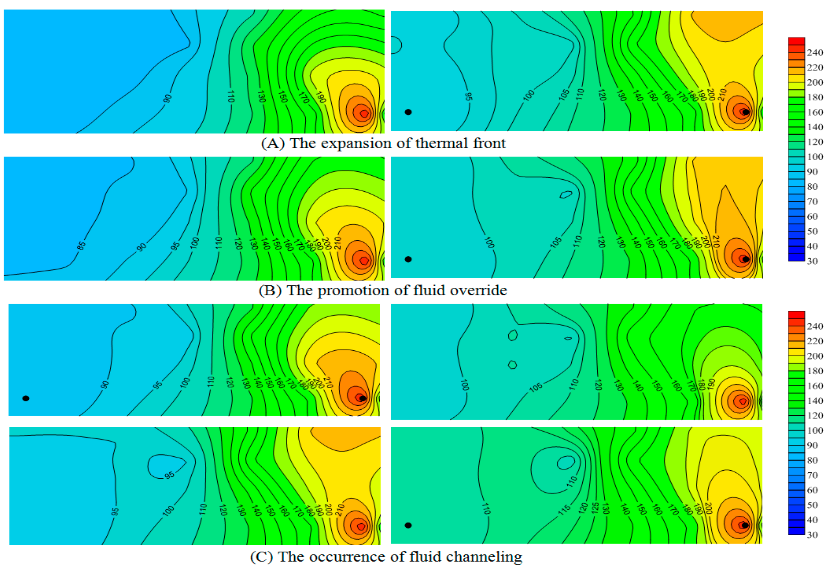

Figure 5. Temperature distribution in different stages of nitrogen-assisted steam flooding [94].

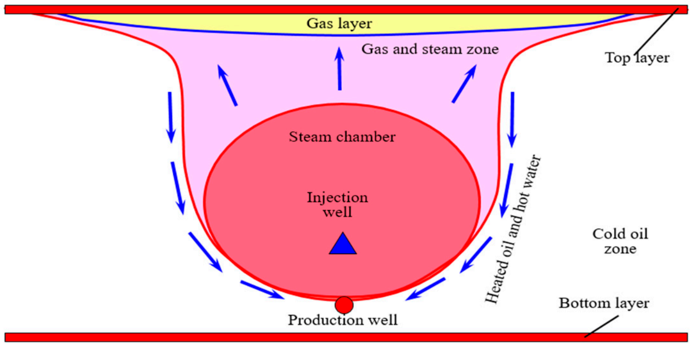

Figure 6. Schematic diagram of SAGP injection.

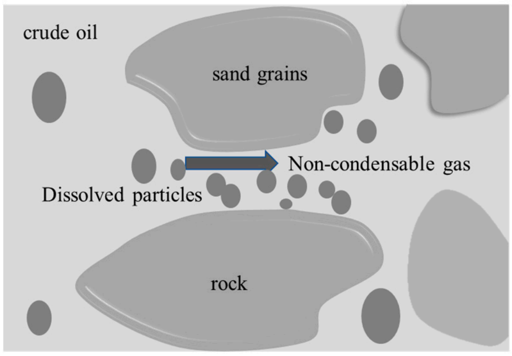

Figure 7. Non-condensable gas displacement process.

6. Advantages and Disadvantages Analysis and Prospect of Non-Condensate Gas Injection

The world economy cannot grow without a huge supply of energy. In recent years, with the increasing amount of oil and gas energy consumption, conventional oil and gas reserves and production are decreasing year by year, and the share of the global energy consumption structure is also shrinking year by year. The unconventional oil and gas represented by heavy oil have received more and more attention.

6.1. Advantages and Disadvantages Analysis of Non-Condensate Gas Injection

(1) Advantages

In heavy-oil development, steam injection technology is the most widely used technology. However, due to the limitation of reservoir pressure and heat loss, this thermal recovery technology is not ideal for ultra-deep heavy-oil reservoirs with a buried depth greater than 2000 m. Non-condensate gas injection is an important way of tertiary oil recovery, which has many advantages in the exploitation of heavy-oil reservoirs. First of all, under the reservoir condition, the injected gas and heavy-oil contact many times to achieve dynamic miscibility, which has a significant viscosity-reduction effect on heavy oil. In recent years, people have started to pay more attention to CO_2 to improve the recovery of heavy-oil reservoirs. This technology can not only improve the recovery of heavy-oil reservoirs, but also solve the problem of CO_2 sequestration and inhibit the greenhouse effect [6,99]. Second, the performance of non-condensate gas injection is almost not limited by reservoir depth. For deep heavy-oil reservoirs with thin formation and low permeability, it has better effect and higher economic benefits than thermal recovery. Water-sensitive reservoirs, bottom water reservoirs, and other reservoirs that are not suitable for water-flooding development can also be developed by injecting non condensable gas. Last, the non-condensate gas injection operation requires simple equipment.

(2) Disadvantages

However, for shallow heavy-oil reservoirs, the reservoir pressure is generally low, and gas injection will lead to the rise of formation pressure. The formation-bearing pressure of shallow oil reservoirs is relatively low, and it is generally difficult to reach the gas miscibility pressure. For field applications, N_2 injection is generally suitable for deep reservoirs over 3000 m. The miscibility pressure of CO_2 and hydrocarbon gas is low, which is suitable for shallow reservoirs. When the reservoir temperature is less than 38 °C, N_2 injection cannot achieve miscibility, but hydrocarbon injection and CO_2 injection can achieve miscibility more easily.

The gas injection is also suitable for low-permeability reservoirs since gas diffusion is limited because of low permeability, which improves contact between gas and crude oil and creates favorable conditions for miscibility. Under high reservoir permeability, gas injection may cause early gas channeling, resulting in reduced oil-displacement efficiency.

6.2. Future Prospects

(1) Non-condensable gas prospect

However, injecting CO_2 into heavy-oil reservoirs can improve oil recovery, and it can also realize the geological storage of CO_2, which can improve environmental pollution and climate change to some extent. In recent years, foreign scholars have proposed CO_2/N_2 composite gas EOR technology [100,101]. Although domestic scholars have carried out a lot of studies on EOR by gas injection, most of them focus on a single-gas injection medium such as CO_2 and N_2. Recently, a new type of heat carrier (MTFs, multiple thermal fluids) has been introduced into the heavy-oil recovery process [102,103]. As a new heat carrier, MTFs are different from the traditional mixed gas of steam and non-condensate gas. The non-condensate gas in MTFs is a mixture of N_2, CO_2, CH_4, and CO. Therefore, the MTF-based process can also be considered as a steam–solvent–gas co-injection process. In addition, non-condensate gas can also be applied to heavy-oil reservoirs with water at the bottom [104]. Water cone has always restricted the effective development of heavy oil reservoirs. In order to prevent or slow down the occurrence of water cone, non-condensate gas or non-condensate gas foam can be used. After use, the rise of aquifer can be effectively controlled to some extent.

(2) New technique prospect

The main difficulties in the development of heavy-oil resources at the present stage are to improve the recovery of heavy-oil reservoirs in the late stage of thermal recovery and to efficiently develop the hard-to-use heavy-oil reservoirs after a long period of steam injection development. Serious formation pressure loss and the development of cross-well channeling channels have become the main factors restricting the development effect of heavy-oil thermal recovery. Steam–non-condensable gas, steam–chemical agent, and steam–organic solvent combined thermal recovery to enhance oil recovery technology can effectively solve the problems faced in the late thermal period. The key to the implementation of this technology is to select the appropriate additive types from non-condensate gases, solvents, and chemicals. At the same time, it is the focus of the attention of oil companies to seek efficient and low-cost additives. At present, it has been proved in field applications that the thermal composite development method will be the key technology to realize the late stage of steam thermal recovery of conventional heavy oil and the efficient development of hard-to-use heavy-oil reservoirs.

In contrast to waterflooded light-oil reservoirs, an EOR process for heavy-oil resources is more challenging. Common technologies include an in situ combustion process, a thermal-solvent process, a thermal-NCG (non-condensable gas, such as N_2, flue gas, and air) process and thermal-chemical (such as polymer, surfactant, and geland foam) process. The offshore multi-component thermal fluid injection process and the thermal CO_2 and thermochemical (surfactant and foam) processes of onshore heavy-oil reservoirs will be some opportunities in the next decade. In addition, the new electrical method, in situ upgrading (such as ionic liquids, and the addition of catalyst and steam nanoparticles) and novel wellbore configuration have also attracted some attention [105]. The effective development of heavy-oil reservoirs in the whole life cycle is a process of continuously improving oil recovery. It is the most important task to evaluate the performance of effective new technology and select the best process, not only from the laboratory experiment, but also from the field.

7. Conclusions

This research reviewed the enhanced heavy-oil-recovery technologies using CO_2 and N_2 in China. Both the mechanisms and applications of these enhanced heavy-oil-recovery technologies were reviewed in detail.

(1) Heavy-oil reservoirs are generally developed by thermal recovery, which mainly involves steam injection development, hot water injection development, reservoir fire, and so on. Steam injection development accounts for 97% of the total heavy-oil production. However, in the process of steam injection development, there are many problems, such as the large heat loss of wellbore, serious cross-flow between wells, influence of steam overburden, and unequal production of profile, which result in the difficulty of producing the remaining oil of heavy-oil reservoirs and the increasingly poor production effect.
(2) Heavy-oil production by injecting non-condensate gases such as CO_2 and N_2 into the formation and relying on the principles of gas expansion and viscosity reduction, evaporation extraction, and formation energy replenishment is a replacement development technology for the problems of insufficient formation energy and low steam sweep coefficient in the late stage of steam huff-and-puff development, which can effectively improve the steam huff-and-puff effect in high-wheel wells.
(3) The condensate-gas-assisted steam injection has more obvious effect than a single gas injection, and the condensate-gas-assisted steam injection technology can greatly improve the physical characteristics of a single vapor phase, making the heat-carrying fluid compressibility stronger, and, with the expansion of the higher performance, can effectively reduce the viscosity of crude oil, improve the seepage flow characteristics of heavy oil, and improve the effect of reservoir development.
(4) At present, the thermal composite development technologies, based on steam–non-condensate gas, steam–chemical agent, and steam–organic solvent, are the key technologies for the efficient development of heavy-oil reservoirs in the late stage of steam thermal recovery and difficult-to-produce heavy-oil reservoirs. The development of new technology will bring a qualitative leap to the petroleum industry.

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