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Novel Schemes for Improving Recovery Factor of Ultra-thin Low-permeable Sandstone Reservoir by CO2 Flooding, Case Study: CCUS project in V Reservoir, Canada

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ABSTRACT

The V reservoir is ultra-thin, low-permeable sandstone with net pay of less than 3m and air permeability of 5.1 mD. Its primary recovery is 10% of OOIP due to low permeability and high heterogeneity. CO2 miscible flooding has been implemented since 1998 to improve oil displacement and increase oil production. This paper discusses a case study on the field to show effect of a new CO2 EOR scheme.

This paper presents a CO2 flooding development plan specifically tailored to ultra-thin sandstone reservoirs with strong heterogeneity. A modified line drive flood pattern was designed to make full use of the monocline structure of the reservoir. Moreover, the development plan minimized the adverse effects of gravity segregation by injecting CO2 at the structurally high part of the reservoir and producing oil at the low part. The injection-production well pattern is designed to overcome facility constraints by placing vertical producers in the thicker part of the reservoir sand body, while horizontal producers in the thinner part of the edge sand body. The method of water-alternating- gas (WAG) injection was adopted to improve the sweep efficiency and have a better conformance control in the late stage of CO2 flood.

The actual production results of the oilfield show that with the new CO2 flooding development plan, the recovery rate has increased by 22%, and the daily oil production has also increased from approximately 10 m3/d before the implementation of the plan to 100 m3/d approximately. After historical matching, the dynamic model statistical calculation results of the reservoir numerical simulation also show that the CO2 miscible sweeping volume reaches more than 82% of the total sand volume. It is predicted that the ultimate recovery factor can reach higher than 50%. The above good oil displacement effect comes from the effectiveness of the following methods. The monocline structure has a favorable dip angle creating a gravity overriding effect on CO2 flood. When CO2 is injected at the high structure and migrates to the low structure, it fully interacts with the crude oil, boosting oil recovery. Horizontal wells are used in thin sand formations to significantly maximize contact with the reservoir and enhance oil flow. The technique of alternating gas and water injection is used with dynamically adjusted pressure to create a "gas lock," blocking high permeability areas and reducing gas channeling.

This paper depicts the guidance to efficiently develop the ultra-thin, low-permeable reservoir. The new scheme includes methods such as injecting CO2 into the high part of the reservoir and producing oil at the low part, using horizontal wells to produce thin sand bodies at the edge, and dynamically adjusting the gas and water alternating injection pressure to reduce gas channeling.

Keywords: CCUS, CO2 flooding, ultra-thin formation, low-permeable reservoir, water and gas alternating injection

1. INTRODUCTION

A large number of research and application results show that CO2 flooding is the main technology to solve the problem of difficult energy supplement and low oil recovery in low permeability reservoirs (Gao et al. 2009; Bi et al. 2018; Taber and Martin 2001). Injecting CO2 into the reservoir can greatly improve oil recovery. At the same time, the reservoir is an underground gas storage with good sealing conditions. The CO2-EOR process has gained increased appeal as it has the potential to sequester CO2, thereby reducing global greenhouse gas (GHG) emissions. A sponsored study by the International

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Energy Agency (EIA) has estimated that CO_2-EOR has a global storage capacity exceeding 61 Gigatonnes, with an average utilization factor of 6.0 Mscf/Stb (0.3 tonnes/Stb). This utilization factor is an average calculation of 16 CO_2-EOR projects in the USA, excluding recycled CO_2, and is likely based on intermediate to heavy oils (McKean et al., 1999). The utilization factor for light oil with very low viscosity has been estimated to be 2.63 Mscf of CO_2/Stb (0.141 tonnes/Stb) of incremental oil, according to another study (Bon and Sarma, 2004). Therefore, using CO_2 as an oil displacement agent to improve oil recovery can not only increase the recoverable reserves of crude oil, but also realize the long-term geological storage of CO_2, which can not only achieve the social benefits of CO_2 emission reduction, but also produce huge economic benefits. It is one of the best ways for CO_2 storage and efficient utilization.

In 1978, Stalkup provided an overview of the CO_2-EOR process, which included the identification and evaluation of CO_2 resources. Gardner et al. (1981) conducted experiments to examine the CO_2 phase behavior of Wasson crude oil at two different pressures. Orr et al. (1984) expanded on this study by interpreting pressure-composition phase diagrams for binary CO_2-Wasson crude oil mixtures. Dai et al. (1987) used simulation to study the effects of microscopic heterogeneity in rock pore structures. Shyeh-Yung (1991) carried out experimental investigations to understand the incentives for near-miscible CO_2 processes. Blunt et al. (1993) provided an extensive economic review of CO_2-EOR.

According to Zhang (2015), the rate of oil production in tight oil reservoirs is heavily influenced by several factors, including the expansion of contact area between the well and the target formation, enhanced relative permeability of oil, decreased viscosity of oil, and modified wettability. In the United States, CO_2 flooding has been regarded as a highly favorable gas injection method since 1970 (Holm, 1976; Goodrich, 1980; Klins, 1984). Pittaway (1985) identified several recovery mechanisms associated with CO_2 flooding, including the swelling effect, viscosity reduction, interfacial tension reduction, and light components extraction. This process is considered as a highly effective enhanced oil recovery (EOR) technique for tight oil reservoirs (Manrique, 2006), as CO_2, whether in a miscible or near-miscible state, leads to greater oil recovery than water flooding (Shyeh, 1991; Hadlow, 1992; Bardon, 1994; Thomas, 2014; Dong, 2001; Sohrabi, 2005; Arshad, 2009; Bui, 2010; Ren, 2011; Tsau, 2014). Lake (1989) noted that transitioning a well from water to gas injection after a prolonged water cycle can result in a short-lived increase in production. Generally, the water alternating gas (WAG) process is superior to continuous water or gas injection in terms of oil recovery (Wilson, 2014) and is a promising technique for extracting oil from tight formations (Figuera, 2014). Wettability alteration is a significant residual oil mobilization mechanism during the WAG process (Teklu, 2015). Although several CO_2 field applications in low permeability reservoirs have been successful, some CO_2 injection trials in tight formations have proven to be uneconomical (Leena, 2008). Therefore, it is necessary to thoroughly investigate the CO_2 EOR process in tight oil reservoirs to establish guidelines for screening candidate reservoirs and parameters.

The CO_2-EOR process can be categorized as either miscible or immiscible. To achieve a miscible oil-recovery process, the reservoir pressure must be maintained above the minimum miscibility pressure (MMP). This allows CO_2 and trapped oil to become completely miscible, with CO_2 extracting light and intermediate hydrocarbons from the oil phase. As a result, the interfacial tension becomes zero and capillary pressure disappears, allowing the oil phase and CO_2 phase (which contains some extracted hydrocarbon components) to flow more easily through the porous media. According to Fai-Yengo et al. (2014), capillary pressure has a negligible effect on oil recovery in the Bakken formation. The extraction of hydrocarbons is highly dependent on the density of CO_2, with CO_2 extracting more and heavier hydrocarbons as its density increases. At pressures between 1000 and 4000 psi and temperatures above its critical temperature of 87.9 °F, CO_2 density varies from 0.1 to 0.8 g/cm3. Holm and Josendal (1982) discovered that hydrocarbon extraction is adequate when the CO_2 density is around 0.42 g/cm3, which is close to the CO_2 critical density of 0.468 g/cm3. In practice, CO_2 injection is usually a multiple contact process since it is initially challenging for the injected gas to be miscible with the in-situ oil, particularly for light and medium oil reservoirs.

While CO_2-EOR in conventional reservoirs has been extensively studied, it remains a relatively new field in unconventional reservoirs with low-permeable matrices and natural fractures. In their study, Hawthorne et al. (2013) proposed five conceptual steps for CO_2 injection in low-permeable formations: (1) CO_2 flows into and through the fractures, (2) unfractured rock matrix is exposed to CO_2 at fracture surfaces, (3) CO_2 permeates the rock due to pressure, carrying some hydrocarbons inward; however, the oil is also swelling and extruding some oil out of the pores, (4) oil migrates to the bulk CO_2 in the fractures via swelling and reduced viscosity, and

(5) as the CO_2 pressure gradient decreases, oil production is slowly driven by concentration gradient diffusion from pores into the bulk CO_2 in the fractures. Furthermore, their CO_2-exposure experiments with rock samples from the Bakken formation demonstrated that CO_2 is effective in improving oil recovery. In naturally fractured reservoirs, the primary mechanisms for gas-EOR include viscous forces, gravity drainage, and molecular diffusion.

The aim of this paper is to provide a guide for the effective development of an ultra-thin, low-permeable reservoir. The proposed approach involves several techniques, including injecting CO_2 into the upper part of the reservoir while extracting oil from the lower part, utilizing horizontal wells to produce thin sand bodies at the reservoir's edges, and dynamically modifying the pressure of water-alternating-gas injections to minimize gas channeling.

2. OVERVIEW OF THE V RESERVOIR

The V reservoir is located about 100 Km directly south of Edmonton, Canada. This reservoir, which belongs to the Cretaceous age, is situated in the Western Canadian Sedimentary Basin and is primarily composed of fine to coarse grained sandstone with interbeds of conglomerate and cherty conglomeratic sandstone. Additionally, the coarse beds contain nodular phosphorite, coal fragments, and concretionary siderite. By using facies sequence analysis of well cores and interpretation of wireline log signatures combined with sequence stratigraphic concepts, it has been demonstrated that the V reservoir comprises of two main stratigraphic sequences separated by a major unconformity. The reservoir is a northwest-southeast trending accumulation. Regional dip is south-westerly, averaging approximately 0.5o, so that the structural component of trapping and its effect on fluid flow is minimal. The average net pay of reservoir is 1.5 m . The information above is supported by research conducted by Reinson (1985) and Reinson et al. (1988).

In 1985, the drilling of well 16-32 led to the discovery of the V reservoir. Following this, an additional 19 wells were drilled in the pool over the next four years. Three more wells were added in 2000, and in 2007, the 10-33 horizontal well was introduced. In 1998, a miscible flood was initiated using ethane as the solvent, and wells 06-04, 06-33, and 16-33 were converted to injection. In 2001, well 16-05 was also converted to injection. Ethane injection continued until 2005, after which the pool returned to primary depletion. Initially, the oil production rate increased from 15 to 126 m3/d, but it subsequently declined rapidly as the solvent broke through to the production wells and the gas-oil ratio (GOR) rose rapidly.

Towards the end of 2005, the miscible flood was restarted, but this time, carbon dioxide (CO_2) was used as the solvent instead of ethane. The wells were utilized as injectors as in the previous ethane flood. In September 2008, well 08-32 was converted to injection, despite exhibiting low injectivity. Similar to the earlier ethane miscible flood, there was an initial increase in oil production, but it subsequently declined as the CO_2 broke through to the production wells. To preserve the reservoir, the produced CO_2 was re-injected. Since it contained other reservoir components, the injected gas's composition changed over time. Tracer tests were carried out to determine the communication between the injectors and producers.

In February 2010, the 06-33 injection well underwent a conversion to a water-alternating-gas (WAG) mode, where water is injected for a period followed by CO_2, and the cycle is then repeated. The initial results showed promise, as the desired water injection rates were achieved, and the gas-oil ratio (GOR) at the nearby producing wells declined. However, subsequent CO_2 injection revealed a decrease in injectivity. In certain cases, the CO_2 injectivity increased with time in each cycle. Later in 2010, the other injection wells, along with well 11-05, were also converted to WAG mode. In March 2011, wells 14-28 and 14-33 were converted to injection in WAG mode as well.

A decrease in pressure from 7700 Kpa to 1400 Kpa was observed under primary depletion, as anticipated. The pressure increased to approximately 8000 Kpa during the ethane flood. However, under the CO_2 flood, the pressure had to be increased to over 16000 Kpa to ensure the miscibility of CO_2 with oil.

3. RESERVOIR SIMULATION MODEL

The reservoir model constructed and run on the simulators had the following features:

(1) A 77×151×7 grid, resulting in 81389 blocks, of which 14814 were active.
(2) The gas-oil contact (GOC) was set at 545.5 mss, which resulted in a small gas cap.
(3) The oil-water contact (OWC) was set at 570.0 mss, which is below the reservoir and resulted in no bottom water.
(4) The top of the model was defined by the top of structure map.

(5) The net pay, porosity and permeability for each grid block were taken directly from the geological maps provided.
(6) The initial reservoir pressure was set to 7700 Kpa at a reference depth of 545.5 mss.
(7) The ratio of the vertical to the horizontal permeability was set to 0.1.
(8) The fluids were characterized by a nine-component equation of state (EOS).
(9) Relative permeability and other petrophysical data were taken from previous studies, lab data and analog data.
(10) Production wells were controlled by the historical oil production, input as monthly averages. The two wells in the gas cap, 06-34 and 16-33 were controlled by the historical gas production.
(11) Injection wells were controlled by the historical solvent injection rates, input as monthly averages.
(12) Under WAG, the actual dates of the CO_2 and water injection were honoured. For each injection period, the average injection rate for that period was used as the control for the well.

4. SCENAIRO OF NEW SCHEMES

To fully utilize the reservoir's monoclinic structure, a modified line drive flood pattern was created (as shown in Fig. 1). The development plan aimed to reduce the negative impact of gravity segregation by injecting CO_2 at the high point of the structure and extracting oil at the lower part. To overcome facility limitations, vertical producers were situated in the thicker part of the reservoir sand body while horizontal producers were placed in the thinner edge sand body. To enhance the sweep efficiency and improve conformance control during the late phase of CO_2 flood, the water-alternating-gas injection method was implemented.

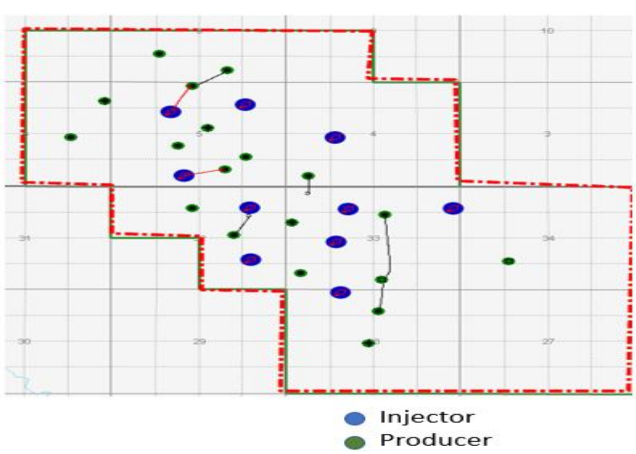

Fig. 1. Injection pattern: A modified line drive

5. RESULTS AND DISCUSSIONS

5.1 History Match

In terms of the specific situations, history match was carried out through the following modifications. Capillary pressure and the shape of rock type (relative permeability) curves were modified for pool history match. Local modifications, such as reservoir conductivity and porosity of the grid blocks around the wellbore, and well productivity index, were performed for single well history match. The results of history match were shown from Fig. 2 to Fig. 5.

The results of history match above demonstrate that the dynamic reservoir model does a good job of matching the pool history. The model successfully matched the pool water production for the first time by incorporating mobile water saturation which was assigned by the capillary pressure. Based on ranking of cumulative oil production, 23 out of 29 producers were selected to match on the production. Priority of history match is from high to low: oil, gas and water. A tolerance of the match is generally +/- 5% but not at the expense of failure in oil production match. However, with the reservoir heterogeneities and complex development processes in the V reservoir, it is difficult to match all of its performance of individual wells. Thus, the dynamic reservoir model and the associated fluid and rock properties are adequate to make predictions on a pool scale.

5.2 Residual Oil Saturation Distribution

The above historical match results illustrate that the reservoir performance model after parameter adjustment is reliable (the match ratio is above 90%, and the error tolerance is within 5%). As shown from Fig. 6 to Fig. 9, the residual oil distribution in the reservoir needs to be delicately analyzed and described to provide a solid basis for the future work or for taking "increasing oil and controlling water" measures.

Fig. 6 shows that gas cap volume was reduced in the Northeast. Some gas pockets exist in the reservoir due to CO_2 injection. Fig. 7 is a section A-A' taken from Fig. 6. This section clearly shows the position where crude oil invades into the gas cap. This is because in the pressurization of CO_2 flooding, CO_2 displaced the crude oil to the gas cap where the reservoir pressure is low (Bardon, 1994).

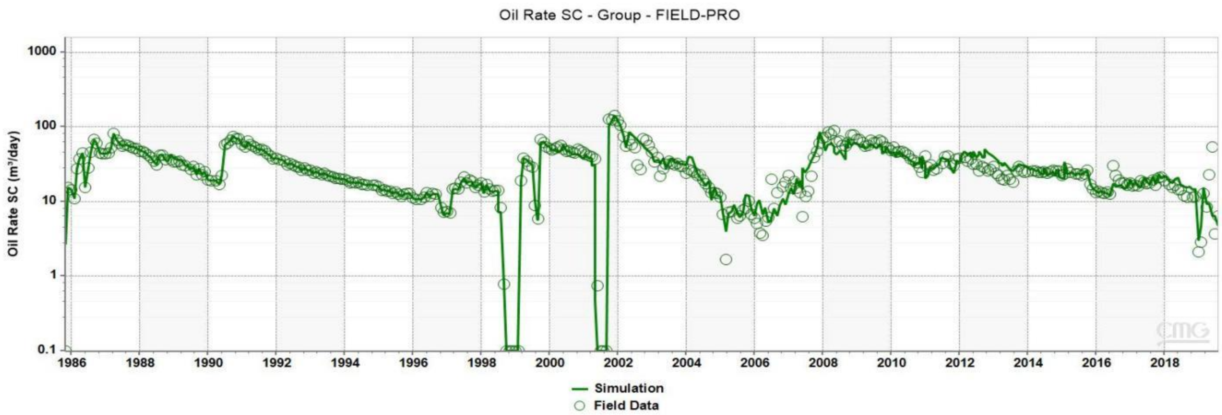

Fig. 2. History match on pool oil production rate is satisfactory

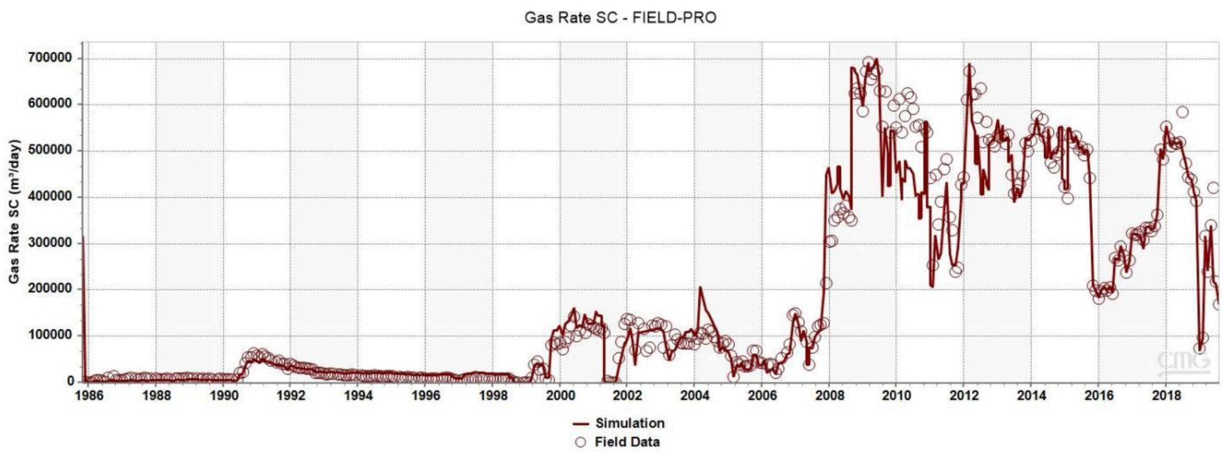

Fig.3. History match on pool gas production rate is satisfactory

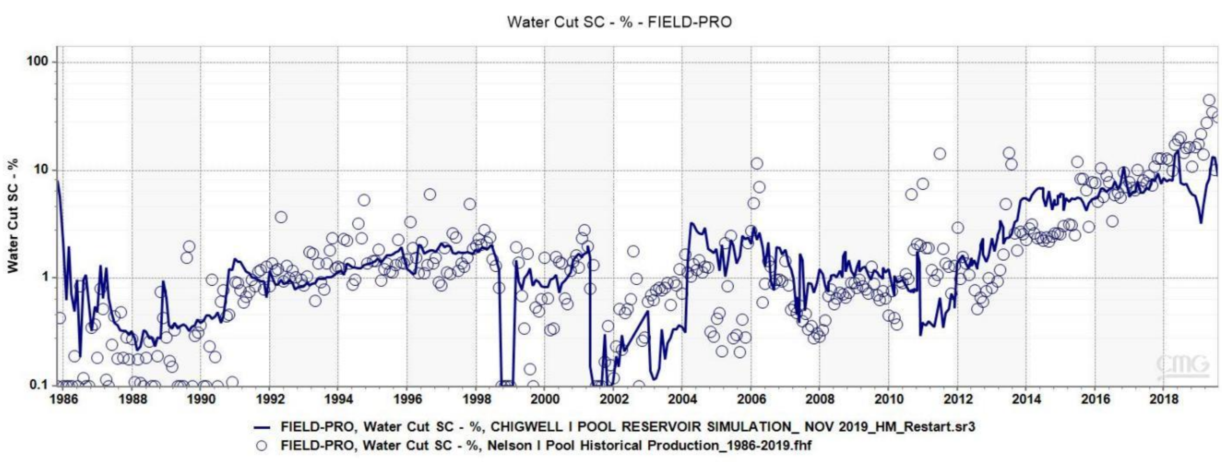

Fig. 4. History match on pool water cut is satisfactory

Fig.8 illustrates the plane residual oil distribution in a layer and the residual oil distribution in the section B-B' at the late stage of CO_2 flood. In the main production zone, a large volume of upswept oil is still left at the pool edge and some adjacent areas. In the low permeable zone, quite a lot of oil remains not mobilized by CO_2. The above phenomena indicate that there is gas channeling during CO_2 flooding. CO_2 preferentially enters the high permeability zone and bypasses the low permeable zone, so that a large quantity of crude oil remains in the low permeability zone and the edge part.

Fig. 9 is variation of oil saturation with time in 3 layers of a grid block (29, 29, 1:3). Layers 1 and 2 are the main production zone. Layer 3 is the low-permeable zone. The curves demonstrate that only oil in layer 1 and 2 is displaced by CO_2 at the production location. For

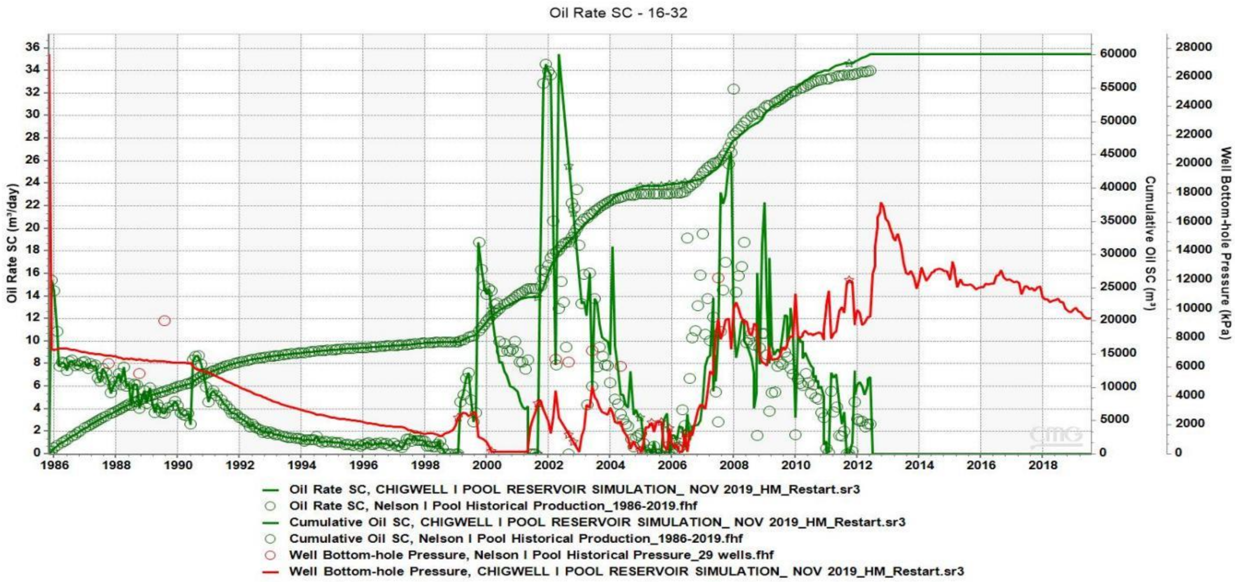

Fig. 5. History match on well 16-32, including oil rate, cumulative oil production and well bottom hole pressure,is satisfactory

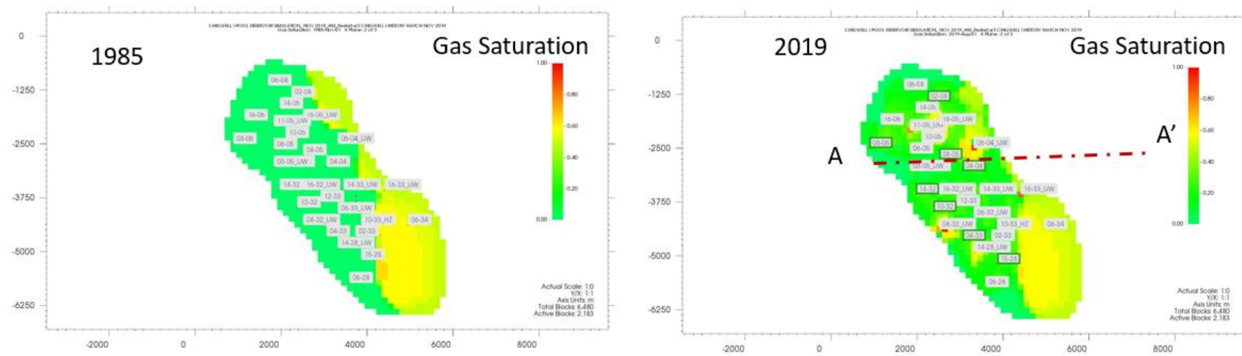

Fig. 6. Comparison of gas saturation distribution between 1985 and 2019

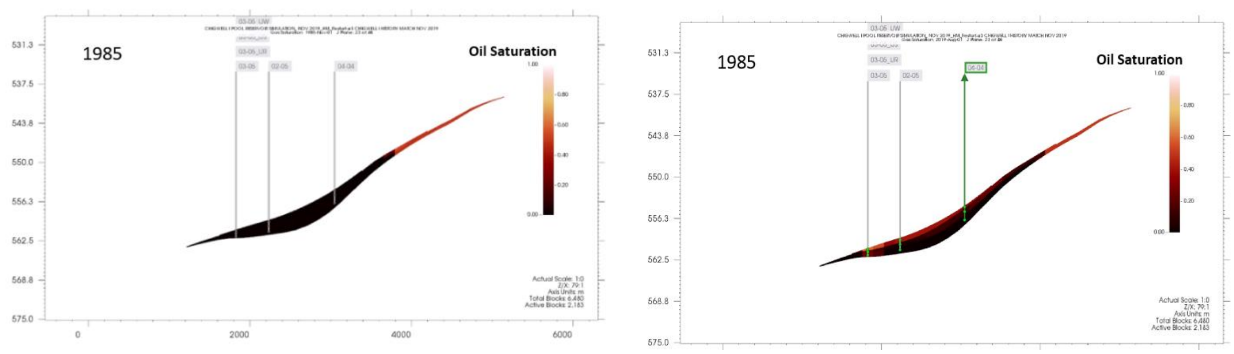

Fig. 7. Oil has clearly invaded into part of the gas cap shown in the section A-A' in Fig.6

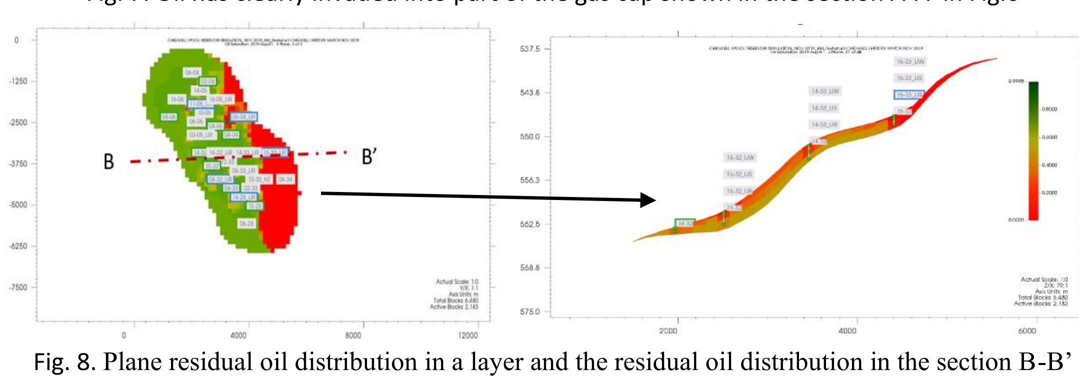

Fig. 8. Plane residual oil distribution in a layer and the residual oil distribution in the section B-B'

example, oil saturation in layer 2 at the production got

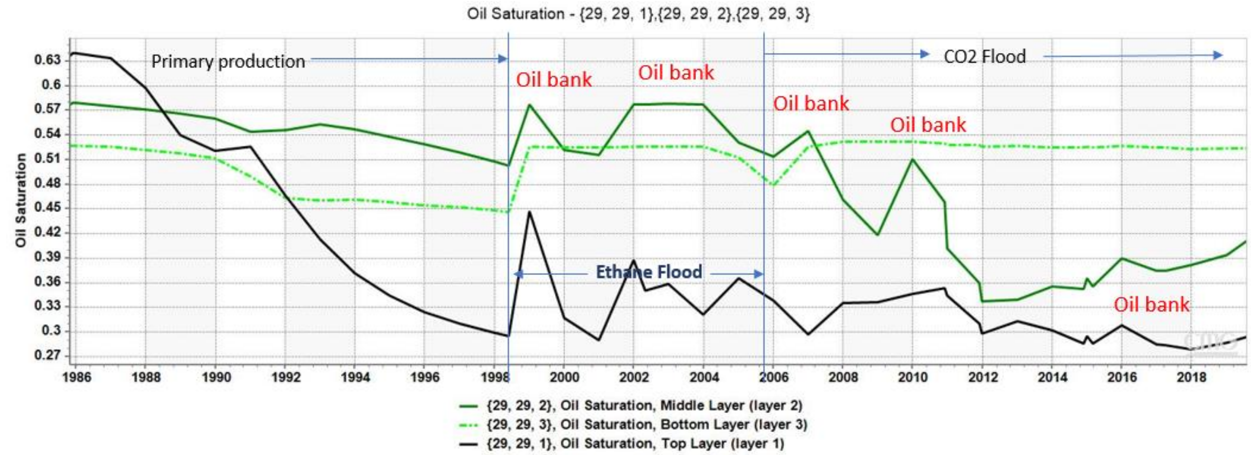

Fig. 9. Variation of oil saturation with time in 3 layers of a grid block (29, 29, 1:3)

down to 34%, decreased by 18% after CO2 injection. Also, the graph shows CO2 is more efficient than ethane in EOR.

5.3 Water-Alternating-Gas (WAG) Mode and Future Prediction

The objectives of WAG mode include mobilizing and recovering the remaining oil in the center of the pool, and increasing the CO2 utilization efficiency. The overview of WAG injection scheme contains the following: (1) Implement WAG in 11 injectors; (2) produce oil from the existing wells and 3 new drilling horizontal wells in the thinner part of the edge sand body; (3) Inject a primary CO2 slug first, followed by a number of cycles of WAG.

In the simulations, the sensitive parameters, such as size of primary slug, WAG ratio (volume of water slug to that of gas), cycle duration and number of cycles, are adjusted and optimized to obtain the best incremental recovery factor and CO2 utilization efficiency. The simulation results were shown in Table 1.

Table 1 Simulation results after 5 years with sensitive parameters

Primary slug size HCPV	Injection Duration month		WAG ratio	Total HCPVI	Incr. RF* %	Monthly utilization MSCF/ STB	Cummulative utilization MSCF/STB
	water	gas					
0.25	1	4	1:17	1.10	5.0	155	69
0.25	1	3	1:12	1.04	5.1	112	66
0.25	2	3	1:6	0.83	5.7	67	50
0.25	3	4	1:5	0.84	5.3	73	52
0.25	3	3	1:4	0.75	5.7	58	45
0.25	4	3	2:5	0.67	5.7	74	39
0.25	6	3	1:2	0.57	5.7	47	34

Note: Incr. RF* is defined the oil recovered after three new horizontal wells on production, divided by OOIP.

From Table 1, the higher WAG is better. The WAG ratio is recommended to be 1:4. During water injection periods, the water injection rates should be the maximum. The injection capacity has potential to increase due to higher injection pressure achievable currently. It is also known that the sensitivity tests have not reached an optimum WAG ratio due to constraints of reservoir pressure and injectors' injectivities. It is recommended to maximize the water injection during the water injection half cycles if injectors' injectivities allow.

With the above optimal combination of sensitive parameters, a WAG development scheme was designed. The well deployment locations are shown in Fig. 10.

In the development scheme, 11 injectors are divided into two patterns which will undergo WAG process. The gas and water are injected alternately and changed every two months in each pattern. 12 cycles in 5 years are tested in the anticipation simulations. The results are shown from Fig. 11 to Fig. 14.

Fig.11 shows that, after WAG implementation, oil decline rate is increased significantly. Oil production rates fluctuate in a range from 250 BOPD to 350 BOPD for 5 years. Fig. 13 demonstrates that, compared with base case (continuous CO2 injection), WAG can increase the recovery by 6.1% with 3 new horizontal wells drilled in the lower part of reservoir edge. Fig.14 presents that WAG's CO2 utilization is nearly 3.0 times higher than the continuous CO2 injection's at the end of WAG. As mentioned earlier, the reservoir has serious heterogeneity. During continuous injection of CO2, the contact opportunity between CO2 and the remaining oil in the formation is reduced, thus reducing the oil displacement efficiency (Ren et al. 2011). This situation often occurs in the lens and permeability pinch-out in the reservoir. In addition, because the viscosity of CO2 is far lower than that of oil and water in the reservoir, CO2 miscible flooding in layered heterogeneous reservoirs is more sensitive to the properties of the formation (such as different permeability) than water flooding. Injected CO2 often enters the high permeability layer preferentially, so that the low permeability layer is

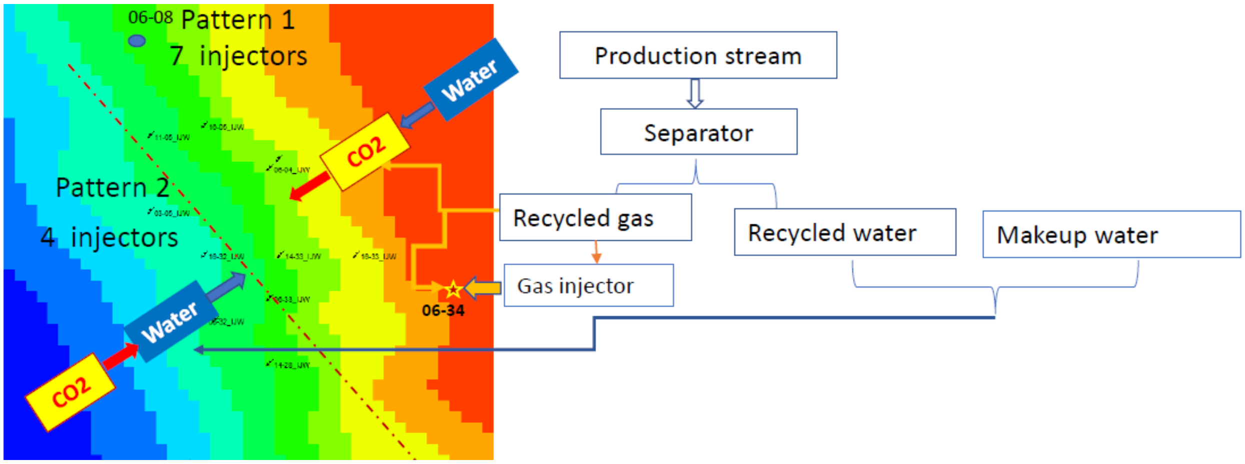

Fig. 10. Pool injection schematic diagram of new development scheme with the optimal combination of sensitive parameters

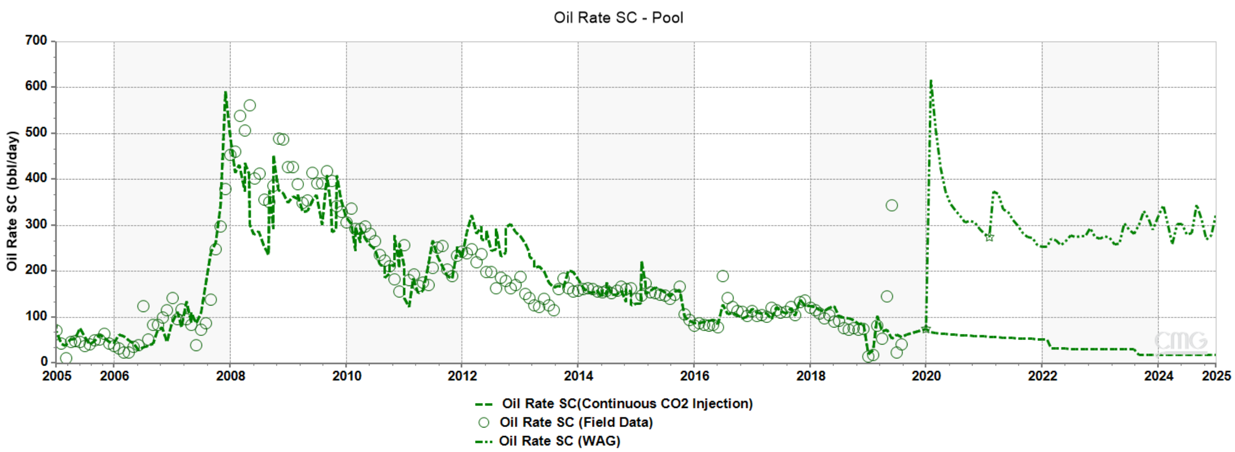

Fig. 11. Oil rate prediction for 5 years

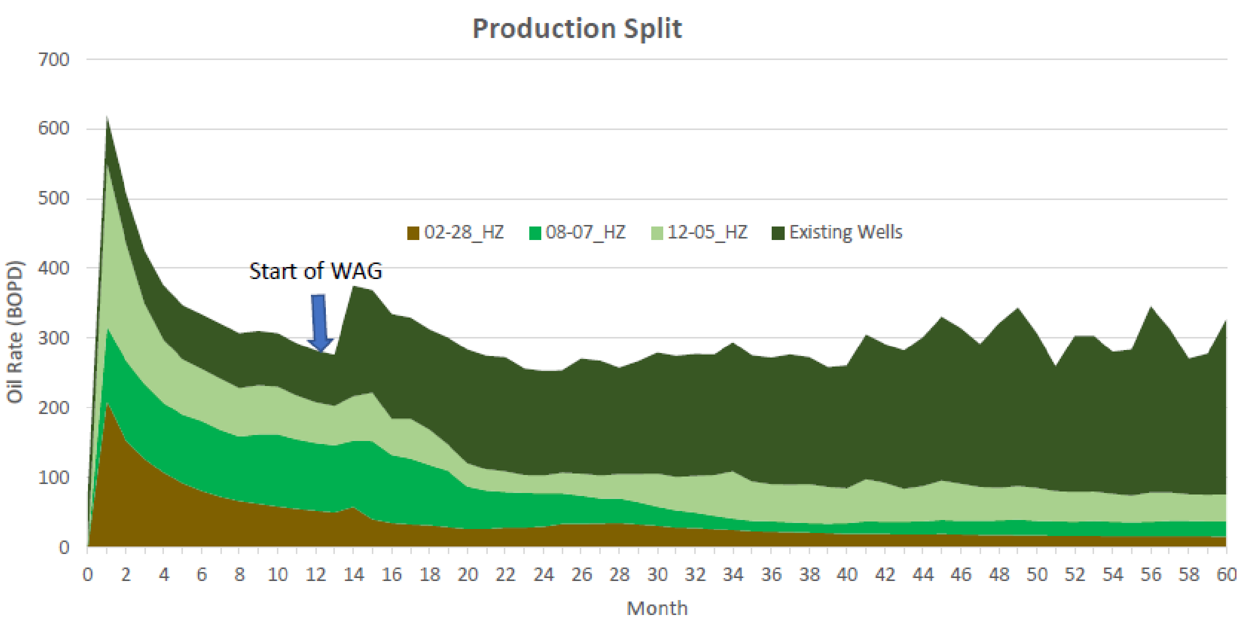

Fig. 12. Predicted oil production split for 5 years

partially or completely affected. The result is that CO2 has broken through from the high permeability layer into the production well. The production well has early gas breakthrough and low recovery degree. Therefore, the layered heterogeneity reduces the oil displacement efficiency. In the vertical displacement, the layered heterogeneity will hinder the downward migration of injected gas, and the upwardly blocking effect of the

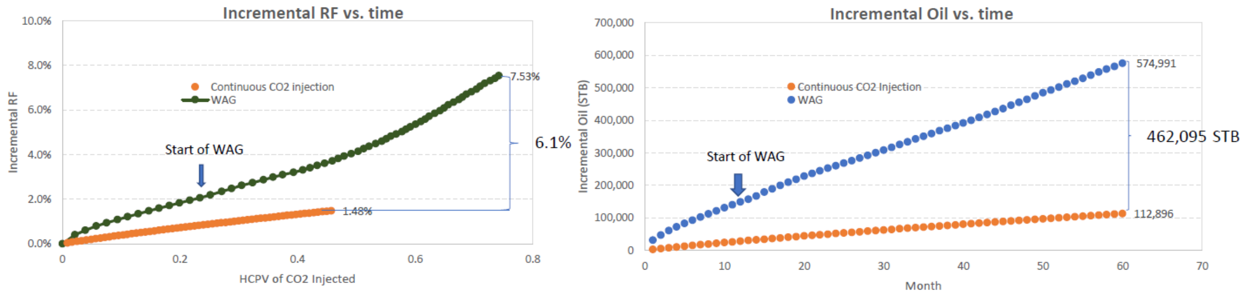

Fig. 13. Anticipated incremental oil in 5 years

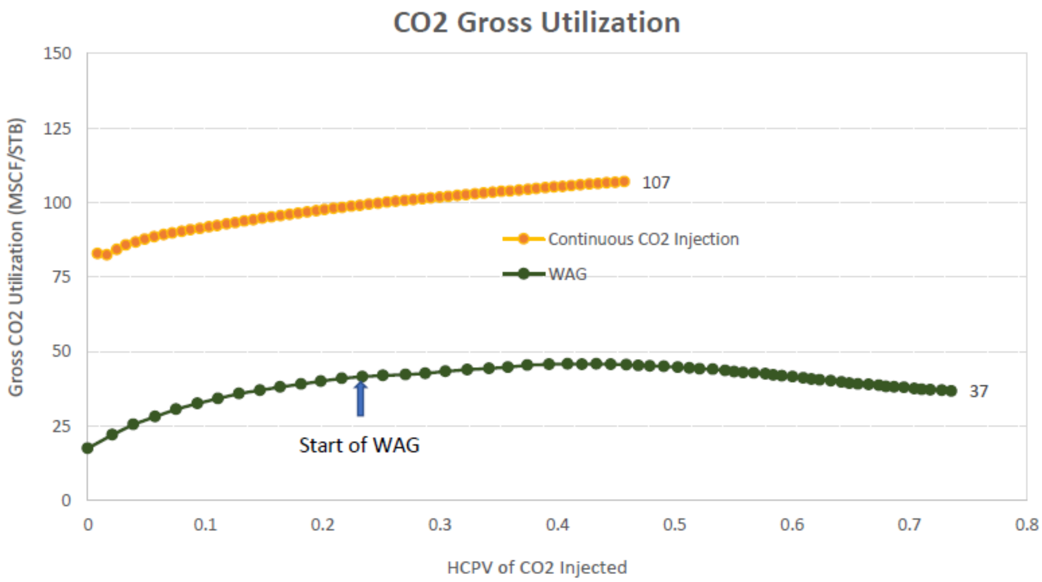

Fig. 14. Anticipated CO2 utilization for 5 years

barrier in the low permeability layer will cause a large loss of injected gas. With WAG injection, the CO2 gas can be injected slowly, fully mingled and promoted as a whole by dynamically adjusting the injection pressure. When the slowly injected CO2 gas enters the high permeability zone, it has sufficient time to stay in the macropores and form a "gas lock" at the pore throat, so as to reduce gas channeling, expand the swept volume and increase the crude oil production (Dai and Orr, 1987). Accordingly, the utilization efficiency of CO2 is significantly higher than that of continuous CO2 injection.

6. CONCLUSIONS

A new development scheme of CO2 flood was designed and conducted to enhance the oil recovery in the V reservoir. The scheme includes a modified line drive flood pattern. The process involves injecting CO2 at the upper portion of the reservoir and extracting oil from the lower part. Horizontal wells are used to produce narrow sand bodies at the periphery, while the gas and water injection pressure is continuously varied to minimize gas channeling.

The reservoir dynamic model with 81389 grid blocks constructed and run on the simulators, including the features, such as a gas cap, monoclinic structure, thicker sand body in the center part and thinner sand body at the edge part.

The historical match outcomes demonstrate that the adjusted reservoir dynamic model is dependable (with a matching ratio over 90% and an error tolerance within 5%). Consequently, the dynamic reservoir model, together with its corresponding fluid and rock properties, are sufficient for forecasting on a pool-wide level.

A significant amount of unexploited oil remains at the periphery of the reservoir and some adjoining regions within the primary production zone. Additionally, a substantial quantity of oil in the low permeability zone has yet to be mobilized by CO2. These observations suggest the existence of gas channeling during CO2 flooding.

Aim for a higher WAG for better results, with a recommended WAG ratio of 1:4. Maximize water injection rates during injection periods, taking advantage of the potential to increase injection capacity through higher achievable injection pressure.

The implementation of WAG leads to a significant reduction in the rate of oil decline. Oil production rates experience fluctuations between 250 BOPD to 350 BOPD over five years. WAG provides greater benefits to existing wells than new wells after injection. Compared to continuous CO2 injection, WAG can increase oil recovery by 6.1%, which amounts to 462,095 STB of oil. At the end of WAG, CO2 utilization is almost three times higher than that of continuous CO2 injection.

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