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Influence of CO_2 retention mechanism storage in Alberta tight oil and gas reservoirs at Western Canadian Sedimentary Basin, Canada: hysteresis modeling and appraisal

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Abstract
Rapid combustion of fossil fuels in huge quantities resulted in the enormous release of CO_2 in the atmosphere. Subsequently, leading to the greenhouse gas effect and climate change and contemporarily, quest and usage of fossil fuels has increased dramatically in recent times. The only solution to resolve the problem of CO_2 emissions to the atmosphere is geological/subsurface storage of carbon dioxide or carbon capture and storage (CCS). Additionally, CO_2 can be employed in the oil and gas fields for enhanced oil recovery operations and this cyclic form of the carbon dioxide injection into reservoirs for recovering oil and gas is known as CO_2 Enhanced Oil and Gas Recovery (EOGR). Hence, this paper presents the CO_2 retention dominance in tight oil and gas reservoirs in the Western Canadian Sedimentary Basin (WCSB) of the Alberta Province, Canada. Actually, hysteresis modeling was applied in the oil and gas reservoirs of WCSB for sequestering or trapping CO_2 and EOR as well. Totally, four cases were taken for the investigation, such as WCSB Alberta tight oil and gas reservoirs with CO_2 huff-n-puff and flooding processes. Actually, Canada has complex geology and therefore, implicate that it can serve as a promising candidate that is suitable and safer place for CO_2 storage. Furthermore, injection pressure, time, rate (mass), number of cycles, soaking time, fracture half-length, conductivity, porosity, permeability, and initial reservoir pressure were taken as input parameters and cumulative oil production and oil recovery factor are the output parameters, this is mainly for tight oil reservoirs. In the tight gas reservoirs, only the output parameters differ from the oil reservoir, such as cumulative gas production and gas recovery factor. Reservoirs were modelled to operate for 30 years of oil and gas production and the factor year was designated as decision-making unit (DMU). CO_2 retention was estimated in all four models and overall the gas retention in four cases showed a near sinusoidal behavior and the variations are sporadic. More than 80% CO_2 retention in these tight formations were achieved and the major influencing factors that govern the CO_2 storage in these tight reservoirs are injection pressure, time, mass, number of cycles, and soaking time. In general, the subsurface geology of the Canada is very complex consisting with many structural and stratigraphic layers and thus, it offers safe location for CO_2 storage through retention mechanism and increasing the efficiency and reliability of oil and gas extraction from these complicated subsurface formations.

Keywords CO_2 retention · Hysteresis modeling · Tight reservoir · WCSB · EOR · Enthalpy

Nomenclature

CO_2	Carbon Dioxide
DMU	Decision Making Unit
RP	Retention Percentage
IP	Injection Pressure
HNF	Huff-N-Puff
FDG	Flooding
TPV	Temperature Pressure, and Volume
CCS	Carbon Capture and Storage
EOR	Enhanced Oil Recovery
EOGR	Enhanced Oil and Gas Recovery
WCSB	Western Canada Sedimentary Basin

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Introduction

Increasing exploration and production of fossil fuels leads to CO_2 emissions and greenhouse gas effects. The emissions of CO_2 originate from the combustion and consumption of fossil fuels and this overall resulting in climate change (Ameyaw et al. 2019; Sadeq et al. 2018; Pachauri et al. 2014; Meng and Niu 2011; Metz et al. 2005). Besides, the demand for fossil fuels are skyrocketing and consequently, and it is a regrettable occurrence that the CO_2 emissions are inevitable (Pranesh et al. 2018). However, tremendous release of CO_2 in the atmosphere could cause a rise in the global temperature level and severe natural hazards (Thomas 2013). At the same time, it is mandatory to enhance and maintain the global economy since currently the world is running on fossil fuels (Abokyi et al. 2019; Senthil et al. 2019; Marques et al. 2018). The recent withdrawal of the USA from the 2016 Paris Agreement (an accord within the United Nations Framework Convention on Climate Change, which handle the climate change, CO_2 emissions and migration) may affect the climate change management (Harini 2018). So there will be a continuous and uninterrupted supply of fossil fuels in upcoming years. Henceforth, a secure and reliable subsurface location should be explored for the safe disposal and storage of this harmful greenhouse gas carbon dioxide. Also, CO_2 can be used in oil and gas reservoirs for elevating the production rate and this is known as CO_2 Enhanced Oil and Gas Recovery (CO_2 EOGR). For the past four decades, the CO_2 in supercritical form is being used in EOR operations and during this process the CO_2 can also be stored in the reservoir simultaneously (Azzolina et al. 2015). Figure 1 shows the typical schematic diagram of the CO_2 storage in an unconventional reservoir and also presents the schematic diagram of CO_2 EOR. Generally, the efficiency of CO_2 storage depends upon the reservoir depth, pressure, temperature, and lithology (Peck et al. 2018).

As already it was mentioned that CO_2 can be stored in the oil and gas reservoirs during EOGR operations and this is also known as retention mechanism (Mahalingam et al. 2019; Olea 2015). Pranesh et al. (2018) conducted a statistical modeling and evaluation on the subsurface carbon dioxide storage in the Bakken tight oil and the Eagle Ford shale gas condensate reservoirs by retention mechanism. The author has critically reviewed the performance of CO_2 huff-n-puff and flooding in these American unconventional reservoirs. From the author's research it was observed that more than 90% of CO_2 has been retained in these reservoirs and also, revealed that the CO_2 HNF process is better than the CO_2 flooding. Furthermore, Eagle ford shale gas condensate reservoirs offer a good storage site for the storage of CO_2 as it undergoes a phase change to liquid (Pranesh 2016). Additionally, CO_2 retention values mainly depend

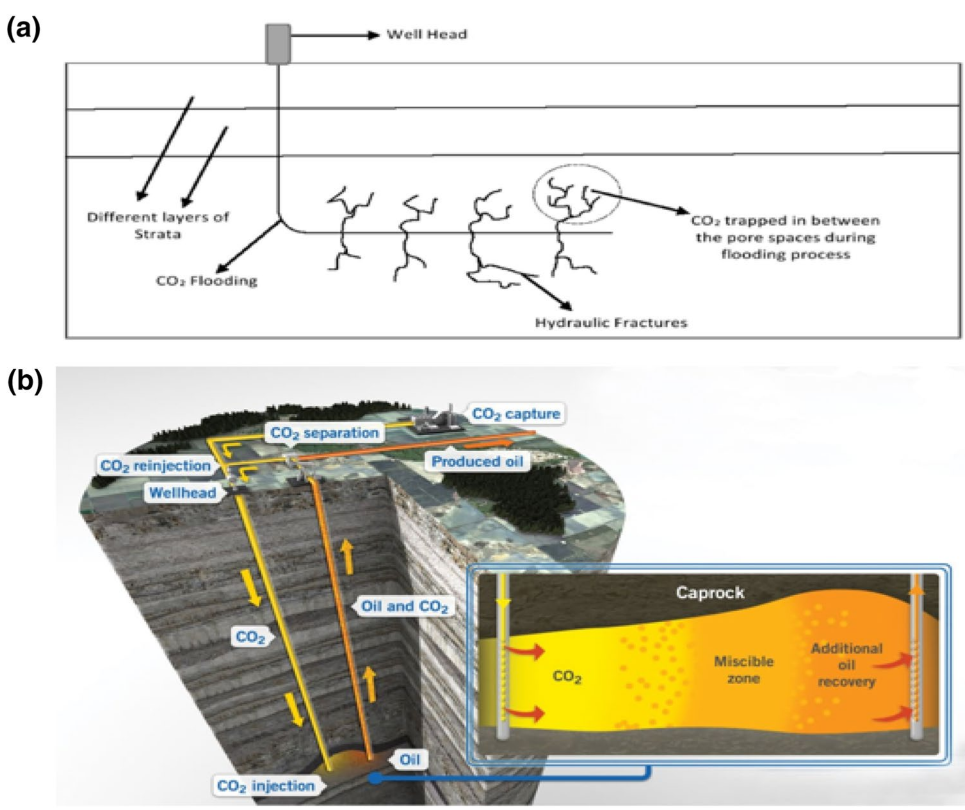


Fig. 1 **a** Schematic diagram indicating CO_2 storage in a typical unconventional reservoir (Pranesh 2018), **b** schematic diagram of CO_2 EOR process (Overton 2016)

on the reservoir heterogeneity as this was observed in the San Andres formation of West Texas, Permian Basin, USA, during CO_2 EOR process (Ren and Duncan 2019). Shelton et al. (2016) critically analyzed the miscible carbon dioxide enhanced oil recovery on the CO_2 storage potential. Actually, the author's have made a statistical and geochemical study on the feasibility of storing CO_2 during the miscible CO_2 EOR process. They studied various basins and reservoirs across the USA, also the depleted reservoir for the viable carbon dioxide storage potential. It was found from their study that many basins and reservoirs across the USA are suitable for the carbon dioxide storage and also, it can increase the rate of CO_2 retention. Moreover, noble and stable isotope determines the CO_2 storage in these locations. Furthermore, in depleted reservoirs, high amount of CO_2 was trapped by residual trapping mechanism during CO_2 sequestration.

Karimaie et al. (2017) conducted a simulation investigation on carbon dioxide enhanced oil recovery and storage potential in a North Sea reservoir. This simulation study was performed by the authors to quantify the CO_2 flooding performance on oil recovery and the results was compared with the performance of the water injection. Various types of CO_2 injection were considered, specifically, the CO_2 Simultaneous-Water-And-Gas (SWAG), and actually, this method was chosen for segregating the gravity between the water and gas. The simulation results indicated that oil recovery factor increased between 3 and 8% while applying CO_2 flooding. In the SWAG method, there is an achievement of mobility control. Additionally, higher CO_2 retention in the reservoir has been accomplished. Dai et al. (2018a) analyzed the effects of supercritical carbon dioxide fluid retention-induced permeability alteration in tight oil reservoir. The author's goal is to characterize the permeability alteration in tight cores during supercritical CO_2 injection. Moreover, microstructural and analytical methods were employed to validate the experimental results. Mainly, it was observed from their research that fluid filter loss has altered the tight core permeability due to the fracturing supercritical CO_2 fluid. Actually, it was observed from their research that formation damage could occur in tight oil reservoirs due to the utilization of supercritical CO_2 as fracturing fluid.

Figure 2 shows the schematic diagram of carbon dioxide retention in the tight oil and gas reservoir rocks. Actually, CO_2 flooding is a method in which CO_2 is injected into an oil and gas reservoirs to enhance the liquid and gaseous hydrocarbon fluids to the surface. It is one of the best tertiary methods for recovering oil and gas to surface during reservoir pressure depletion. Reservoir pressure is a most dominating factor in mobilizing reservoir fluids to the surface systems (Satter et al. 2008; Ahmed and McKinney 2004). During CO_2 injection to a reservoir will undergo a supercritical phase and transform it has supercritical fluid. The CO_2 would be either miscible or immiscible with the reservoir fluids depending upon the reservoir and injection pressures (Zhang et al. 2019a; Gao et al. 2014). Recent reports have demonstrated that near-miscible CO_2 flooding performance is better than miscible flooding in oil reservoirs, as this was experienced in the tight oil reservoir at Jilin Oilfield, China (Ren et al. 2015). Zhou et al. (2019)

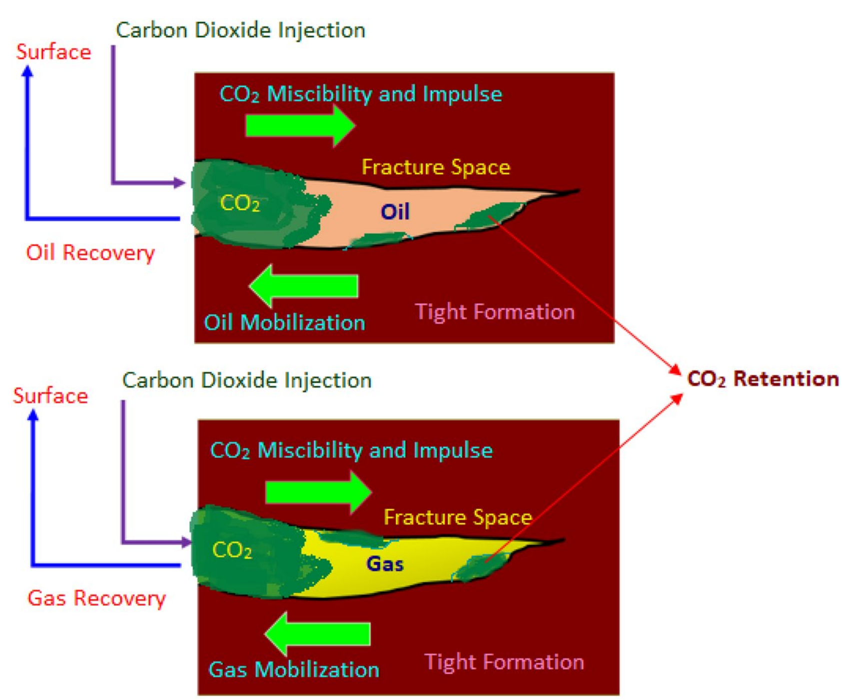


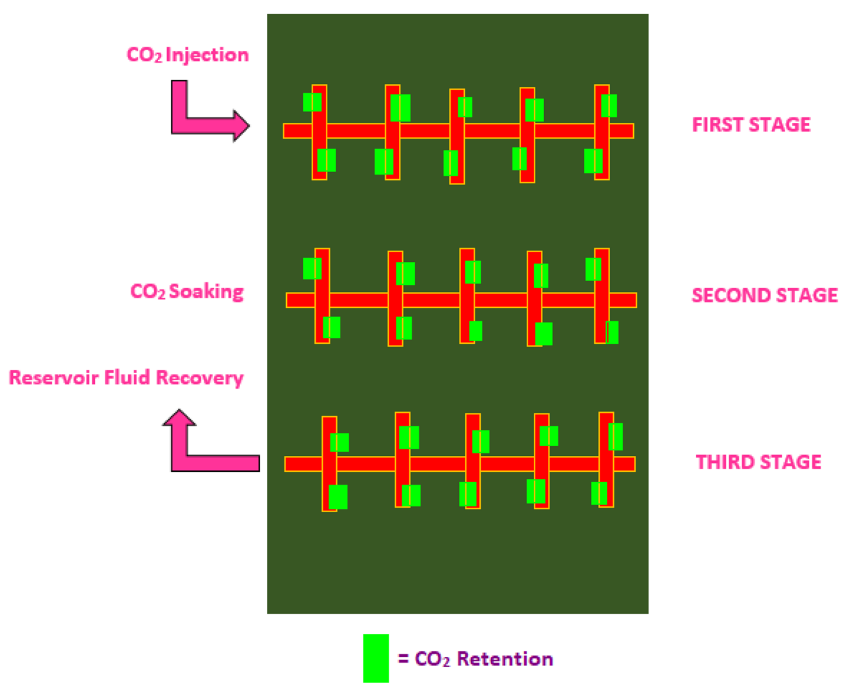
Fig. 2 Schematic diagram of CO_2 flooding process in fracture space

conducted an experimental and numerical examinations on the carbon dioxide flooding process in tight oil reservoir. In their research, three types of CO_2 flooding were used, such as with continuous CO_2 injection process, CO_2 interlinked with soaking period, and CO_2 interlinked with pressure maintenance. These were conducted in one meter longed core plugs for analyzing the carbon dioxide flooding on the oil production performance. Light crude oil was used in the experiment. The experimental results revealed that the CO_2 flooding enhanced the oil production performance and the oil recovery factor has increased to 38.96%. Additionally, to certain extend, the capillary pressure affected the oil recovery and furthermore, the numerical model outcomes showed good agreement with the experimental data.

Wei et al. (2020) studied the adsorption behaviour of supercritical carbon dioxide in tight porous media and triggered chemical reactions with rock minerals during CO_2–EOR and sequestration. Actually, the CO_2 flow in tight reservoirs reacts with quartz and feldspar minerals and undergoing a dissolution. This reactive flow produces clay minerals, and subsequently, the permeability of the porous tight media during coreflood experiment has been fluctuating and this solid clay particles can obstruct the permeability of the tight rocks. Furthermore, supercritical CO_2 flooding can increase the tight rock permeability by 50% roughly. The rock temperature determines the adsorption rate of the supercritical carbon dioxide in tight porous media and the increase of CO_2 pressure has increased the reactions between CO_2 and rock minerals. Overall, their research has demonstrated that CO_2 flooding can enhance the permeability and porosity of tight rocks than CO_2 huff-n-puff, because CO_2 flooding in supercritical form is one kind of rock fracturing fluid. Lan et al. (2019) has reviewed the mechanism of microscopic seepage for the extraction of shale gas by carbon dioxide flooding under supercritical phase. The authors pointed out that supercritical carbon dioxide injection in shale reservoirs not only enhance the recovery of methane, but also sequestrate the CO_2 in the reservoir. The cyclic mass transfer of CO_2 and CH_4 drives the recovery of the reservoir fluids to the surface and gas adsorption affects the seepage of the reservoir fluid under extreme conditions. Moreover, hysteresis existence may dominate the desorption process. The adsorption rate of CO_2 is stronger than CH_4 in shale reservoirs due to diffusion rate, molecular polarity, critical temperature, and kinetic diameter. Overall, the change in permeability due to various physical conditions can affect the microscopic seepage efficiency in shale gas reservoirs.

Figure 3 shows the schematic diagram of CO_2 retention during huff-n-puff (HNF) Process. CO_2 huff-n-puff process in one kind of method injection method in which the CO_2 is injected to an oil and gas reservoirs for soaking and will be recovered after certain period. Generally, the performance of CO_2 HNF is better than the CO_2 flooding (Pranesh 2016). Actually, the CO_2 huff-n-puff process consist of three stages as shown in Fig. 3. The first stage consists of CO_2 injection to a reservoir,, and this supercritical fluid will react that is soak with the reservoir fluid and actually, and during this time, the well will be closed for production and this is done in order to maximize the soaking ability of the CO_2 with the reservoir fluid, this process falls under the second stage. The third stage is the hydrocarbons recovery stage and this is performed after

Fig. 3 Schematic diagram of CO_2 Huff-N-Puff process



the soaking phase in which the well is opened for production. Soaking period will increase and maintain the reservoir pressure and thus effectively liquid and gaseous reservoir fluids can be recovered in the third stage (Yoosook et al. 2017). It was reported that the CO_2 huff-n-puff performance is good on enhanced oil recovery from tight oil reservoirs (Pu et al. 2016).

Ma et al. (2019) made an experimental investigation on the factors influencing oil production distribution in various pore sizes during carbon dioxide huff-n-puff in an ultra-high-pressure tight oil reservoir. Initially, the authors analyzed the reservoir geology of the Xinjiang tight oil reservoir, which indicated rate of low depletion recovery, high remaining oil content, low permeability, and complex pore structure. Moreover, it was revealed that waterflooding performance is poor in this tight oil reservoir and therefore, the authors employed CO_2 HNF process to yield the oil production from this tight reservoir. Mainly, it was found from their research that the number of cycles should be limited or it would affect the CO_2 HNF efficiency and oil recovery as well. Additionally, in the first five years of the cycle, the cumulative oil recovery has been increased to 84–91.7%. Interestingly, it was observed from their research that oil production in micro pores increases and decreases in medium to macro pores. Sun et al. (2019) performed compositional simulation of carbon dioxide huff-n-puff process in Middle Bakken tight oil reservoirs with hydraulic fractures. The authors performed a numerical modelling and employed embedded discrete fracture model (EDFM) to assess the performance of CO_2 HNF on oil recovery in the Middle Bakken tight oil reservoirs. Their reservoir simulation outputs revealed that CO_2 HNF process has a positive effect on the oil recovery factor and negative effect was found in the scenario of molecular diffusion. Actually, carbon dioxide of 200 Mscf/day, 50 injection days, 14 soaking days per cycle and with 3 cycles at 500, 2000, and 4000 days has the highest recovery factor and oil production as well. Besides, the rate of CO_2 molecular diffusion is also higher in this case.

Meng et al. (2018) conducted a performance evaluation of carbon dioxide huff-n-puff gas injection in shale gas condensate reservoirs. Initially, the authors studied the phase behaviour of shale gas condensate reservoirs and found that when the reservoir pressure falls below the dew point the condensate occurs and this is the major problem in this type reservoir. So the authors proposed cyclic injection of CO_2 in shale gas condensate reservoirs by huff-n-puff process. It was revealed from their research that the number of cycles should be optimized in order to avoid condensate recovery decrease and CO_2 HNF performance decline. Also, the soaking efficiency depends on the injection pressure, and overall, the CO_2 HNF injection has enhanced the gas condensate recovery for about 30.36% after 5 cycles of carbon dioxide huff-n-puff.

On the whole, the objective of this paper is to perform a statistical modelling on the CO_2 retention in tight oil and gas fields of Alberta at Western Canada Sedimentary Basin, Canada. As already indicated that the subsurface geology of Canada is complex and storing CO_2 in this basin is captivating and moreover, it offers a safe and reliable storage of the harmful greenhouse gas CO_2 (Bachu 2016). The structure of this paper is described in this section. The second section presents the Western Canada Sedimentary Basin and its oil and gas fields of the Alberta Province, Canada. The third section presents the research methodology that was used in this paper. The fourth section critically examines the results that were obtained from the statistical modeling and the fifth section concludes the paper.

Western Canada Sedimentary Basin

Canada holds world's third largest proven oil reserves and mostly found in oil sands, bitumen, and tight oil (Dale 2019). Also, Canada is the fifth largest producer of the natural gas, which is estimated to be 1225 trillion cubic feet (tcf) of remaining natural gas resources (Canadian Association of Petroleum Producers 2019). The Western Canada Sedimentary Basin (WCSB) is a huge sedimentary basin that covers 1,400,000 km^2 of the Western Canada, which includes northeastern British Columbia, Alberta, Saskatchewan, and to some extend of the southwest of the Northwest Territories. The basin comprises of immense sedimentary rock wedge running from Rocky Mountains in the west to the Canadian Shield in the east (Wright et al. 1994). Figure 4 shows the geological map of the Western Canadian Sedimentary Basin. Furthermore, WCSB is more than 6 km northeastern tapering wedge of sedimentary rocks, which extends southwest from the Canadian Shield into the Cordilleran Foreland thrust belt. Its internal structure and the lateral variations in its shape reflect a long and complicated history of development that involves Foreland basin, which was superimposed on a cratonic platform and continental terrace wedge (Porter et al. 1982). The WCSB has the major share of the Canada's tight oil and gas reservoirs. Specifically, the Alberta Province under the WCSB of Canada has 1 billion barrels of conventional crude oil reserves, 166 billion barrels of bitumen reserves, and 423.6 billion barrels of shale oil in place. Additionally, 31 trillion cubic feet of conventional natural gas resources, 3424 trillion cubic feet of shale and siltstone based hydrocarbon resource in place (Natural Resources Canada 2019). Also, there is a large deposits of bitumen in this basin, which of highly varying composition and bio-degradable (Bennett and Larter 2018).

Actually, there is a common implications on the hydrocarbon generation (kerogen) in the Alberta region of the WCSB is due to the effects of temperature, reservoir depth, vitrinite

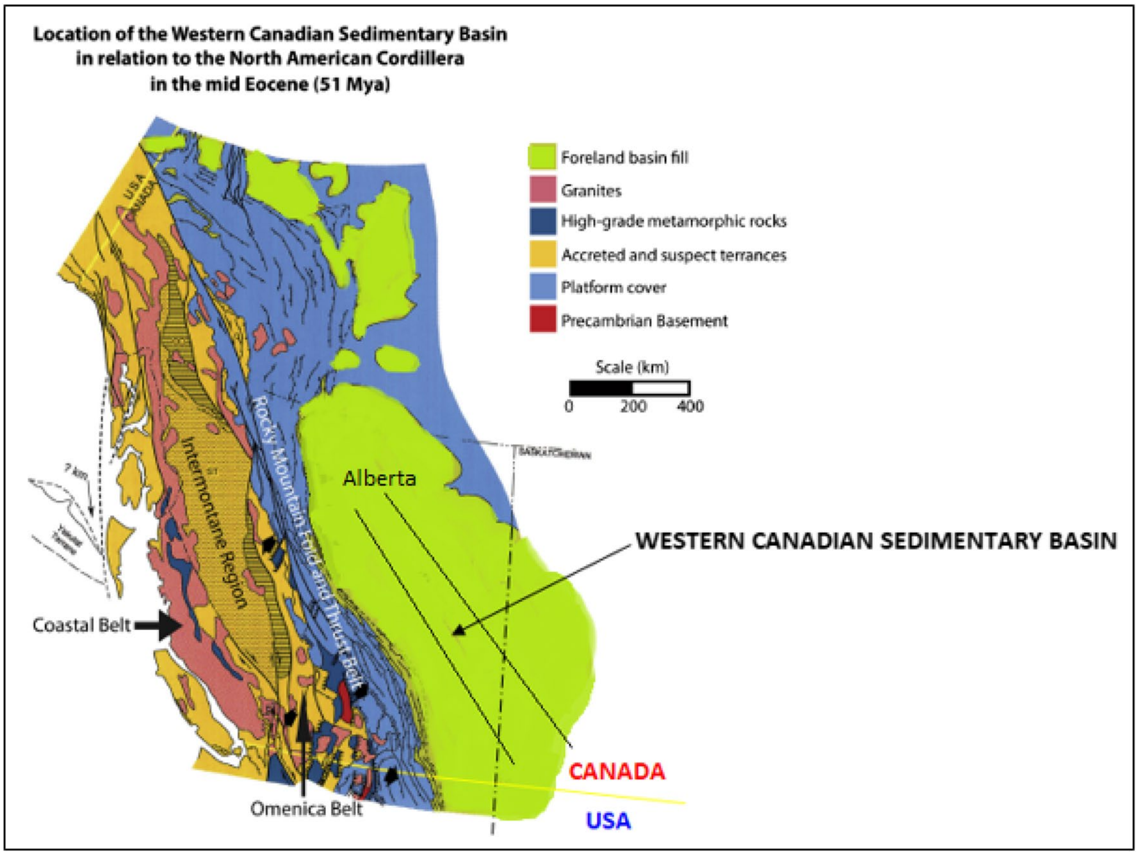


Fig. 4 Geological map of Western Canada Sedimentary Basin (Palmer-Wilson et al. 2018)

reflectance, and thermal maturity. Also, it was emphasized that thermal maturation and diagenetic effects are the likely cause of the changes in the hydrocarbons and mineralization (Wetering et al. 2016). Additionally, in the shale formation of the Western Canada Sedimentary Basin, the pore size distribution is the key control for microbial activity and methanogenesis (Yin et al. 2016). Moreover, there is an attractive and good CO_2 storage potential in the Western Canada Sedimentary Basin, specifically in the Alberta Province (Cote and Wright 2010). Earlier itself, it was reported that WCSB offers an excellent storage site for the geological sequestration of CO_2 due its tectonic stability and also, other factors such as water flow and geothermal regime influences the carbon dioxide storage capability (Bachu and Stewart 2002).

Figure 5 shows the subsurface heat distribution in the Western Canada Sedimentary Basin, and due to its extraordinary heat flow nature that is geothermal gradient, the basin has higher potential for geothermal energy resources (Palmer-Wilson et al. 2018), and particularly for the sedimentary enhanced geothermal systems (Kazemi et al. 2018). Banks and Harris (2018) performed a study on the geothermal potential in Foreland Basins at the Western Canada Sedimentary Basin of the western side of the Alberta. The author's analysed the geotechnical and hydrogeological data from the wellbore logs and rocks to identify the geothermal potential. Basin mapping and reservoir characterization have also been conducted. Mainly, it was revealed from their investigation that this basin has an enormous amount of thermal energy and heat distribution, which can be commercially exploited. Furthermore, reservoir depth ranged from about 2500 m to over 5000 m, and formation temperature is over 150 °C. Moreover, there is a high degree of thermal variability in the WCSB. Actually, the heat ranges from 30 m W/m^2 in the south to high 100 m W/m^2 in north and geothermal gradient is from lower level of 20 °C /km to over 55 °C / km, and ultimately, the heat flow-heat generation controlling factors and relationship cannot be determined for the entire Western Canada Sedimentary Basin (Weides and Majorowicz 2014). However, subsurface heat flow and temperature play a vital role in the CO_2 sequestration in subsurface systems (Mahalingam et al. 2019; Pranesh et al. 2018).

Tight oil reservoir

Presently, North America accounts for more than 95% in global tight oil production and specifically, in the WCSB

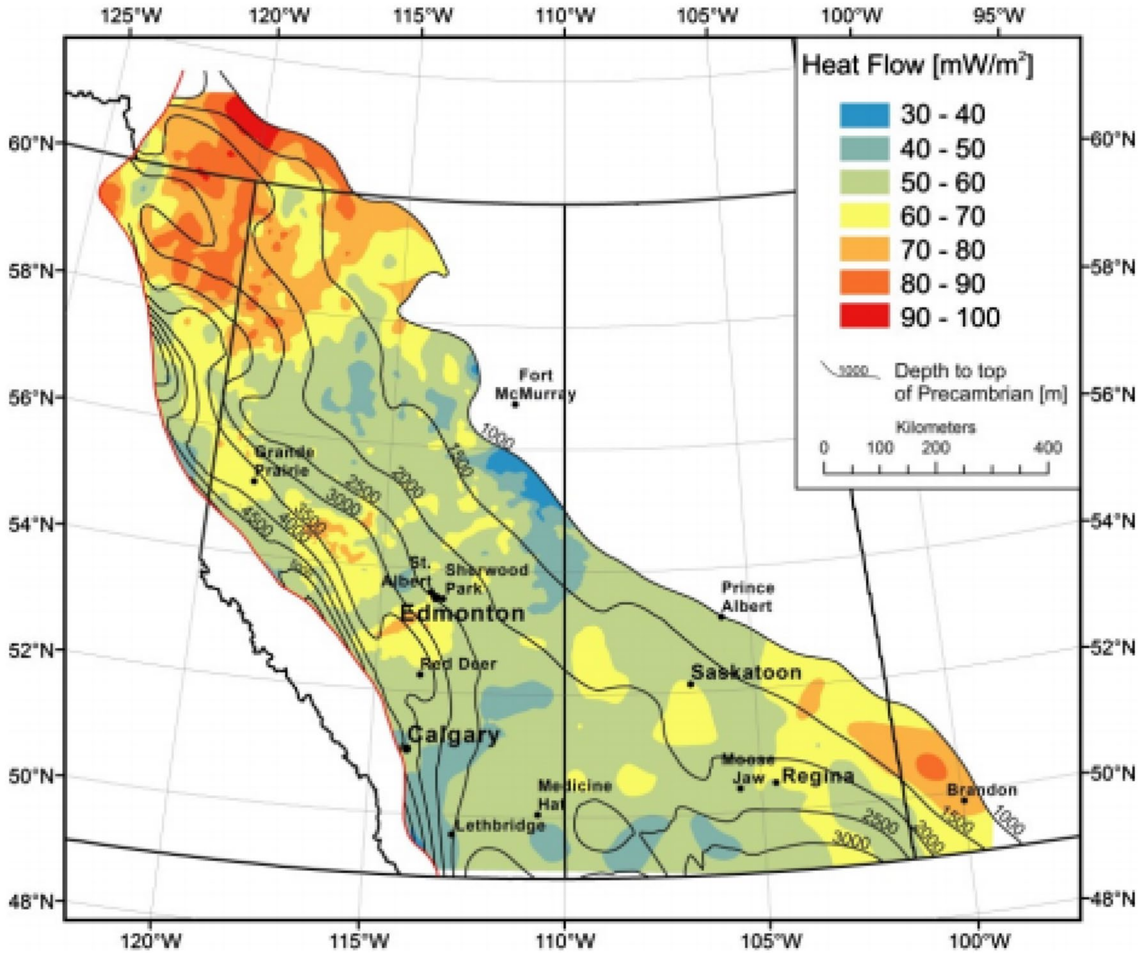


Fig. 5 Subsurface heat flow map of the Western Canada Sedimentary Basin (Weides and Majorowicz 2014)

of Canada, generally, tight oil reservoirs in 78% are marine sediments. Mostly, tight oil fields are located in the Montney formation at Alberta Basin (Zhang et al. 2016). Also, there is a good prospect and potential for tight oil resource in the Upper Cretaceous Cardium, Formation at Western Canada Sedimentary Basin, Canada (Chen and Osadetz 2013). Figure 6 shows the tight oil fields and developments in the Western Canada Sedimentary Basin. In WCSB the tight oil or light tight oil reservoir rocks are characterized by fine grained, very low permeability formations and typically, this type of liquid hydrocarbons are located in the sandstone, siltstone, and carbonate rocks in the Western Canada Sedimentary Basin. Almost, this shale-hosted oil extraction is impossible without hydraulic fracturing.

Friesen et al. (2017) examined the permeability heterogeneity in bioturbated sediments and its implications for waterflooding in tight oil reservoirs of Cardium Formation, Pembina Field, Alberta, Canada. Initially, they authors analyzed the bioturbated sediments recording distal expressions of paralic depositional environments are increasingly being exploited for hydrocarbons in this giant field and basin. The strata in this field is very complex due to limited connectivity between vertical and horizontal permeable beds. Actually, reservoir rock heterogeneity involving permeability is an essential characteristics for the good productivity of the tight oil. But, recently, drilled horizontal wells in this field indicates the bioturbated muddy sandstones and sandy mudstones in paralic environments can be economically recovered, when sand filled burrows provide connectivity between sand beds. However, the well performance in this field is poorly understood and under speculation. Whatsoever, the authors suggest that reservoir rock permeability heterogeneity is the major governing factor on the tight oil well performance and economic viability. Additionally, Ghanizadeh et al. (2015a) conducted petrophysical and geomechanical investigation of Canadian tight oil and liquid-rich gas reservoirs and overall, they made a geomechanical property estimation. The authors have taken the core samples from the Montney and Bakken formations. Their objectives to characterize the fundamental geomechanical properties of

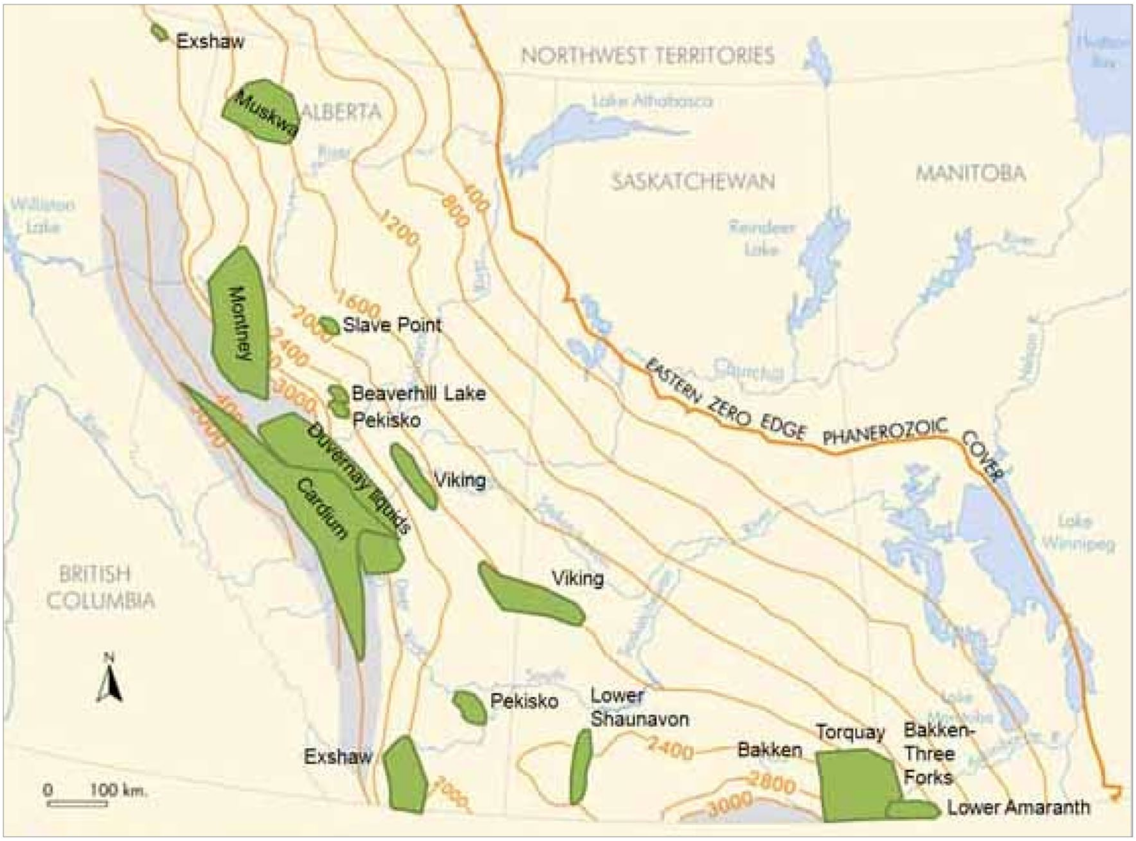


Fig. 6 Tight oil fields map of Western Canada Sedimentary Basin (National Energy Board 2011)

these formations and investigate their relationship between petrophysical and geomechanical behavior of these fine grained tight reservoirs. It was revealed from their research that the geomechanical property of core plugs taken from the Montney Formation is higher than the Bakken Formation, which shows strong and highly stable reservoir tight oil rocks. Moreover, in the correlation, the increasing mechanical hardness decreases the permeability. Hence, it is clear that the WCSB Montney Formation tight oil reservoirs extraction is very difficult than that of the Bakken Formation due to its exceptional geomechanical and petrophysical properties.

Tight gas reservoir

The tight gas reservoirs in the Alberta Province of the Western Canadian Sedimentary Basin are characterized by the coarser-grained framework or in other words the reservoir rocks are in fabric nature that is with rough/harsh texture (Zambrano et al. 2014). In addition, Pujol et al. (2018) studied the physical processes that occur in the tight gas reservoirs in the Western Canadian Sedimentary Basin. Primarily the authors stated that the identification of noble gases in the gas reservoirs of the WCSB helps us to understand the evolution and fluid dynamics of the unconventional gas resources. Actually, elemental noble gases such as He, Ar, Kr, and Xe was found along with natural gas from 18 wells of this basin. These noble gases are in the mixture with gaseous hydrocarbon and also, with water, which is rich in the noble gases. These are mainly composed of radiogenic isotopes such as ^{40}Ar and ^{4}He and this helps us to identify the evolution of source rock and fluid migration to the reservoir rock. On the whole, the radiogenic isotopes instigate the diffusion in the source rock and directs the fluid to migrate to the reservoir rock and therefore, the tight gas reservoirs in WCSB evolution can be understood through geochemical isotopic analysis.

Figure 7 shows the typical three dimensional reservoir simulation model of the Alberta tight gas. Where the top Fig. 7a shows the distribution of shale volume and bottom Fig. 7b shows horizontal well with nineteen stages of hydraulic fracturing. Actually, Vishkai and Gates (2019) investigated the multistage hydraulic fracturing in tight gas reservoirs of the Montney Formation, Alberta, Canada. The authors initially studied the potential of hydraulic fracturing techniques that could potentially enhance the yield of gas recovery from the tight formations. Also, they analyzed and mentioned that optimization of hydraulic fractures in

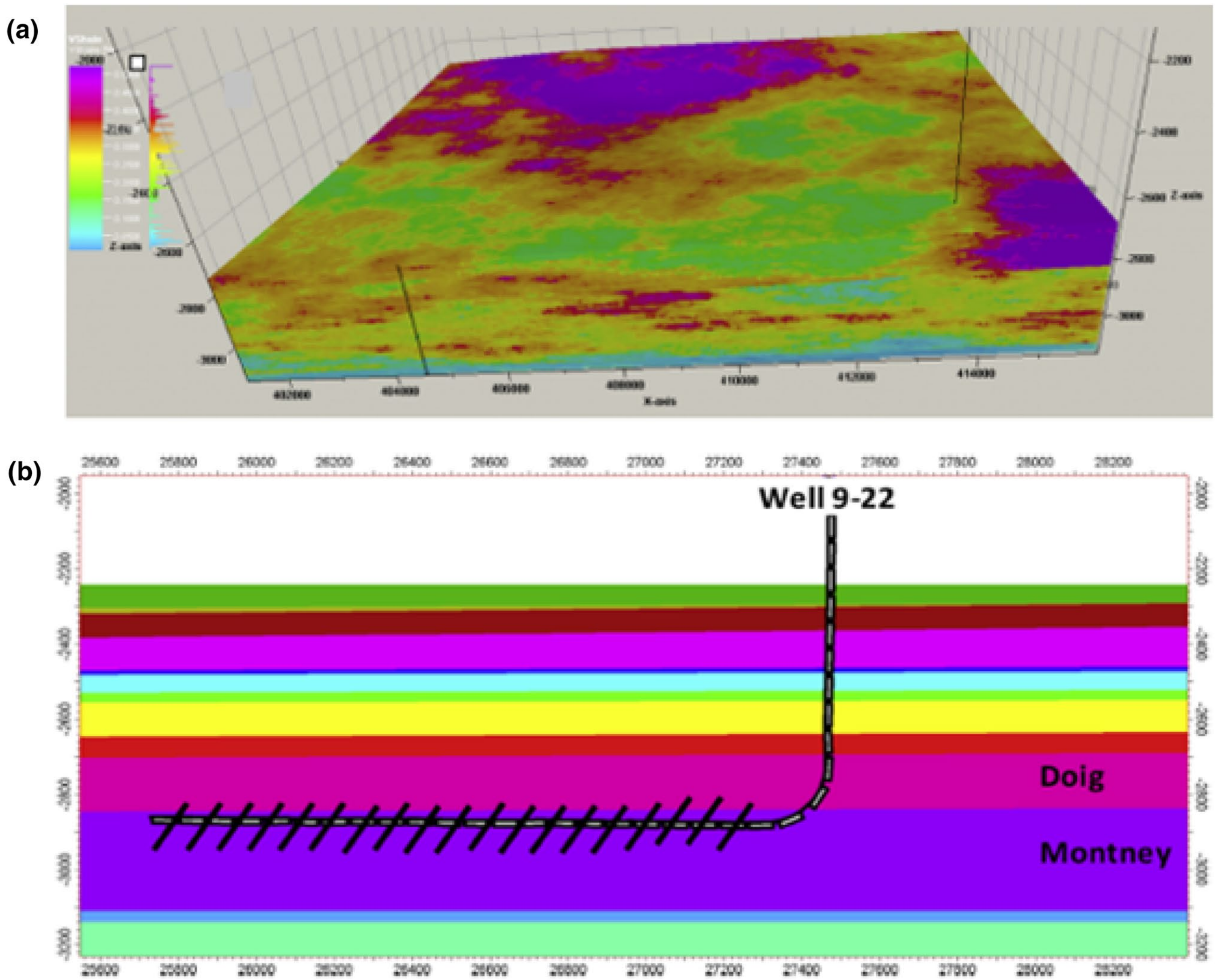


Fig. 7 WCSB, Alberta tight gas reservoir simulation 3D model: **a** shale volume distribution, **b** Horizontal well with 19 stages of hydraulic fracturing (Vishkai and Gates 2019)

the tight gas reservoirs of Alberta, WCSB is very challenging. Hence, they employed 3D tight rock simulator based on the unconventional fracture model to understand the multi-stage hydraulic fracturing in the Alberta Montney Formation, Canada. Their modelling results revealed that there is a high relationship between reservoir permeability and fracture conductivity. Furthermore, stress distribution and elastic rock properties are included. Overall, these factors assist us to optimize the hydraulic fracturing design in the Alberta tight gas reservoirs, Canada.

Materials and methods

The methodology followed in this paper is according to the procedure mentioned in the literature Pranesh et al. (2018). Briefly, the materials and methods consist of three steps,

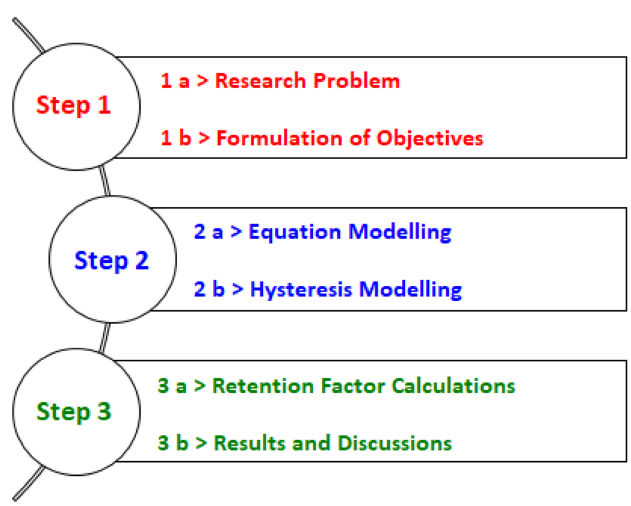


Fig. 8 CO_2 retention mechanism estimation procedure

which showed in Fig. 8. It can be seen from this figure that first step comprises of identifying a research problem and formulating objectives. The second step indicates the modelling of equations and hysteresis, which is a central theme of this paper. Lastly, calculating retention factor and critically analyzing the results falls under third step. Reservoir simulations are already executed using CMG-GEM reservoir software, but these results are not presented in this work. However, reservoir modelling input data can be found in the appendix (supplementary file). Actually, statistical modelling was performed in this research work and this paper focuses on the storage of CO_2 in the Canadian Province of Alberta tight oil and gas reservoirs in the Western Canada Sedimentary Basin. Moreover, Maroto-Valer (2010) stated that typically the retention of carbon dioxide in oil and gas reservoirs needs to be statistically evaluated in order to determine the economic viability of CO_2 sequestration and reservoir fluid recovery.

Furthermore, hysteresis modeling was applied in the Alberta tight oil and gas reservoirs in order to estimate the carbon dioxide retention percentage rates for about 30 years. The calculations were estimated under four sections as described below:

(a) CO_2 huff-n-puff process in the Alberta tight oil reservoir.
(b) CO_2 flooding process in the Alberta tight oil reservoir.
(c) CO_2 huff-n-puff process in the Alberta tight gas reservoir.
(d) CO_2 flooding process in the Alberta tight gas reservoir.

The CO_2 retention percentage was calculated using the Eq. (formula) 1 (Olea 2015), during calculations it is assumed that the amount of carbon dioxide remaining at subsurface is equivalent to the amount of CO_2 trapped by hysteresis.

$$\text{Retention} = 100 \times \frac{CO_2 \text{ Remaining at Subsurface}}{\text{Cumulative } CO_2 \text{ Injected}} \tag{1}$$

The hysteresis trapping of CO_2 is the process in which the carbon dioxide is retarded due to the capillary pressure acting on it are altered and it could be the alteration from the internal friction or fluid viscosity. CO_2 trapping between the rock pores is the major contributor to the hysteresis and due to the impacts of capillary force hysteresis there is a slight advective process observation (Doster et al. 2013). While injecting carbon dioxide into the reservoir, the CO_2 is converted to supercritical phase and it is stored in the fractured/porous rock matrix, that is subsequently, tapped by hysteresis and the fluid gets dissolved in the formation water (Narinesingh and Alexander 2014). Generally, there is a gap between hysteresis and geological heterogeneity during CO_2 EOR and storage (Assef et al. 2019; Agada et al. 2016). Therefore, it is a requirement to fulfill this research gap that is in this case, exploring the mechanism of CO_2 retention in the complex subsurface formations. Following attributions are the major phenomenon occurring in the WCSB Alberta tight oil and gas reservoirs:

(a) CO_2 injected at high well injection pressure.
(b) Permeability and porosity are low.
(c) Early shutdown of the well in huff-n-puff process due to soaking.
(d) Early shutdown of the well in flooding process due to gas adsorption.
(e) Residual trapping of CO_2 due to sequence of subsurface structure and stratigraphic layers.
(f) Restricting CO_2 plume migration due to tight formations with ultra-low permeability.

Results and discussion

This section critically examines and discusses the supercritical carbon dioxide retention profiles in the WCSB Alberta tight oil and reservoirs during CO_2 HNF and FDG processes. The input and output data of the reservoir simulation model can be found in the appendices (supplementary file).

Tight oil reservoir: CO_2 huff-n-puff and flooding process performances

The Alberta tight oil reservoir has been simulated using CMG-GEM reservoir simulation software package. The reservoir model is of length 410 ft and 1800 width and thickness of 45 ft. For the base case he fracture half length is 410 ft, fracture conductivity is 1.5 mD-ft, and the fracture spacing is 55 ft. 17.3%, 0.00003, and 7850 psi are the values for porosity, permeability, and initial reservoir pressure. These values are computed in the reservoir simulated model and the simulation was designed to operate for 30 years. The trapping of carbon dioxide by hysteresis was acquired from simulation results and the percentage of retention was estimated using the Eq. 1. Table 1 shows the CO_2 storage results in WCSB Alberta tight oil reservoir for both CO_2 HNF and flooding (FDG) cases. It can be seen from Table 1 that in first year there were no CO_2 trapped by the hysteresis in both carbon dioxide HNF and FDG process, because of high initial reservoir pressure that automatically exerts the reservoir fluid out of the reservoir. In this case, the CO_2 retention means the amount of carbon dioxide has been successfully filled in the reservoir. In the second year the injection pressure was modelled for 2500 psi and the injection rate (mass) is 45 MSCF/day and the amount of CO_2 retained is 8.235 MSCF and this is the case for CO_2 HNF. While, in year 2,

Table 1 CO_2 storage results in WCSB Alberta tight oil reservoir for both Huff-N-Puff and flooding processes

WCSB Alberta tight oil reservoir							
CO_2 Huff-N-Puff process				CO_2 flooding process			
Year	Injection pressure (psi)	Injection rate (MSCF/day)	CO_2 trapped by hysteresis (MSCF)	Year	Injection pressure (psi)	Injection rate (MSCF/day)	CO_2 trapped by hysteresis (MSCF)
1	0	0	0	1	0	0	0
2	2500	45	8.235	2	9400	210	47.628
3	2500	45	9.252	3	9400	210	56.7
4	2500	45	10.9485	4	9400	210	61.215
5	2500	45	20.7	5	9400	210	111.3
6	2500	45	26.1	6	9400	210	144.711
7	2500	45	33.7635	7	9400	210	148.806
8	2500	45	36.69	8	9400	210	162.939
9	2500	45	37.647	9	9400	210	179.802
10	2500	45	40.689	10	9400	210	188.37
11	4800	120	89.184	11	13,600	430	313.599
12	4800	120	91.416	12	13,600	430	318.2
13	4800	120	92.34	13	13,600	430	321.683
14	4800	120	95.076	14	13,600	430	328.047
15	4800	120	98.592	15	13,600	430	335.572
16	4800	120	99.6	16	13,600	430	353.202
17	4800	120	103.776	17	13,600	430	380.077
18	4800	120	107.004	18	13,600	430	387.559
19	4800	120	109.296	19	13,600	430	396.288
20	4800	120	110.4	20	13,600	430	404.974
21	6300	356	119.1532	21	15,200	620	235.848
22	6300	356	163.76	22	15,200	620	270.63
23	6300	356	206.48	23	15,200	620	310.744
24	6300	356	238.52	24	15,200	620	407.898
25	6300	356	249.2	25	15,200	620	423.336
26	6300	356	249.2	26	15,200	620	432.706
27	6300	356	267	27	15,200	620	503.812
28	6300	356	286.402	28	15,200	620	526.69
29	6300	356	303.3832	29	15,200	620	539.71
30	6300	356	317.4452	30	15,200	620	549.258

9400 Psi and 210 MSCF/day with injection pressure and rate of CO_2 FDG, 47.628 MSCF amount of CO_2 has been retained in the tight oil reservoirs. In the beginning year, the performance of CO_2 FDG is far better than the CO_2 HNF. However, during the following years a linear and slightly sluggish growth was achieved in the yielding maximum retention of CO_2 by hysteresis (MSCF) in both cases. At the end of year 10 in carbon dioxide flooding case, 40.689 MSCF of CO_2 retention was recorded and 188.37 MSCF has been noted in the CO_2 huff-n-puff case. Actually, during CO_2 injection with considerable injection pressure and mass in tight oil reservoirs, it is quite challenging to attain minimum miscibility pressure (Zhang et al. 2018). It can be clearly seen from Table 1 that even in the second decade that is from the year 11 to 20, there is a gradual increase in the CO_2 retentions in both scenarios and the growth continues for the third decade also. At the end of completion year that is the year 30, a CO_2 HNF process in tight oil reservoirs has retained 317.4452 MSCF and 549.258 MSCF has been retained with the CO_2 Flooding process. It should be meticulous that in the case of Alberta tight oil reservoir, the CO_2 flooding contributed in higher CO_2 retention than CO_2 huff-n-puff process. Generally, in tight oil reservoirs, the CO_2 flooding performance will be higher than CO_2 HNF, because in the former case the minimum miscibility pressure (MMP) and reservoir fluid displacement efficiency can be easily attained (Pranesh et al. 2018; Luo et al. 2017).

In Table 1, the successful CO_2 accumulation in the tight oil reservoir has been accomplished. Next Fig. 9 shows the actual CO_2 retention percentage estimation in the Alberta

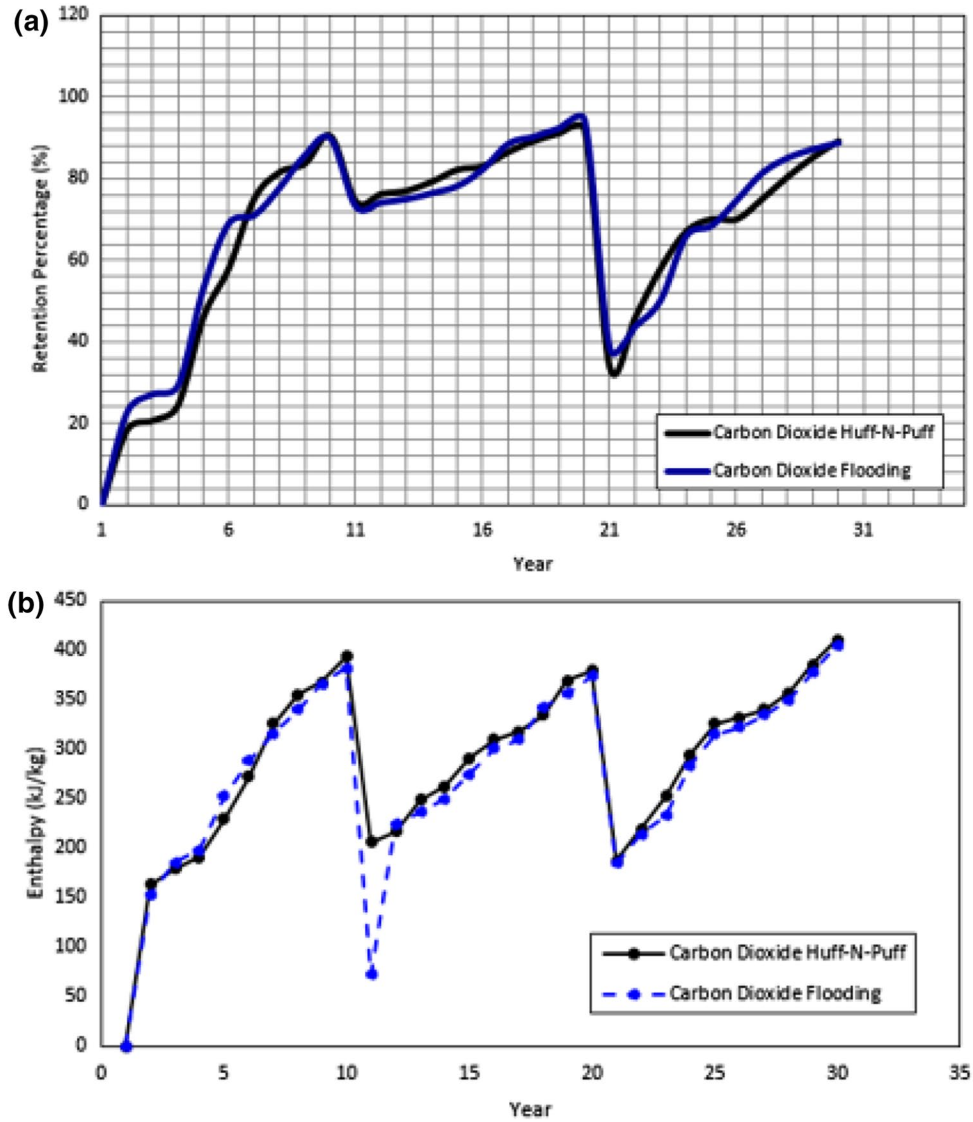


Fig. 9 **a** CO_2 retention estimation in WCSB Alberta tight oil reservoir, **b** subsurface CO_2 retention enthalpy in WCSB Alberta tight oil reservoir

tight oil reservoir. Generally, the CO_2–oil interactions in the tight reservoirs are of extreme interested and major significance in the determination of MMP, wettability, capillary pressure, interfacial tension, and the mobility ratio for EOR and storage. But, during CO_2-oil interactions in tight formations at medium to high reservoir conditions, the CO_2 undergoes a dissolution and causes an oil to expand, since the CO_2 dissolve into oil and expand the reservoir fluids and thereby, triggering CO_2-Oil imbibition (Habibi et al. 2017). This could be one reason for the sporadic behavior of CO_2 retention in the Alberta tight oil reservoir under CO_2 HNF and FDG processes. As it is evident in Fig. 9a, that both carbon dioxide HNF and FDG cases exhibited a sinusoidal and sporadic behavior on CO_2 retention. Initially, in the first two decades, there is a linear growth for both scenarios and in the second decade, the carbon dioxide retention growth is stabilized and slightly incremental. In the first two decades, there is a slight drop in the CO_2 retention and this is attributed to well closure due to extreme reservoir pressure and temperature, and including extreme conditions the injection and production wells. The decline in the third year is mainly due to the CO_2 soaking time for both cases in order to saturate with the reservoir fluid and during this period the well is closed. As already mentioned that some amount of CO_2 could have dissolved in oil phase leading to oil expansion and surface energy. As the latter process dominate the tight oil reservoir volume for CO_2 storage. However, more than 80% of carbon dioxide retention has been achieved in the Alberta tight oil reservoir. Additionally, plume migration is an important factor in the CO_2 sequestration, where the carbon dioxide plume can escape to the top stratigraphic layers through vertical and horizontal permeable rocks (Shariatipour 2013). In this case of Alberta tight formation, the CO_2 plume migration is controlled and prevented even at extreme reservoir conditions. This is feasible due to the structural integrity that is strong geomechanical properties of the Canadian tight formation rocks (Ghanizadeh et al. 2015b).

Figure 9b shows the subsurface CO_2 retention enthalpy in WCSB Alberta tight oil reservoir. In this case, enthalpy means the thermal potential and heat transfer for CO_2 during retention in tight formation at reservoir conditions that includes reservoir rock pressure and geothermal gradient. It can be observed from this figure that the enthalpy values are similar to that of the CO_2 retention values. Actually, the CO_2 enthalpy is directly proportional to CO_2 retention. Therefore, during CO_2 retention there is a high release of CO_2 enthalpy or in other words supercritical heat transfer (Zhang et al. 2019b; Tauveron et al. 2017). Typically, in tight oil formations, oil extraction kinetics during supercritical CO_2 are strongly dominated by the diffusion (Samara et al. 2019).

Figure 10 shows the impact of injection pressure on CO_2 retention in WCSB Alberta tight oil reservoir for CO_2 HNF and FDG cases. Actually, average retention values were calculated for each decade for carbon dioxide HNF and FDG cases. It can been seen from Fig. 10a that for the case of CO_2 huff-n-puff 49.78%, 83.06%, and 67.43% of carbon dioxide retention has been obtained for the injection pressures of 2500 Psi, 4800 Psi, and 6300 Psi. Initially, for two decades, there is linear growth in the CO_2 retention in the Alberta tight oil using CO_2 HNF and at the last decade the growth dropped to 67.43%. A carbon dioxide retention growth decline of 15.63% was noted and this is mainly attributed to the prolongation in the CO_2 soaking time and long time period for reaching the MMP between CO_2 and oil in the tight formations. Furthermore, a similar pattern was observed for the CO_2 flooding scenario, seen in Fig. 10b. Already it was mentioned that the sequence of subsurface stratigraphic layers and irregular structural traps can influence the CO_2 retentions in the Alberta tight oil reservoirs.

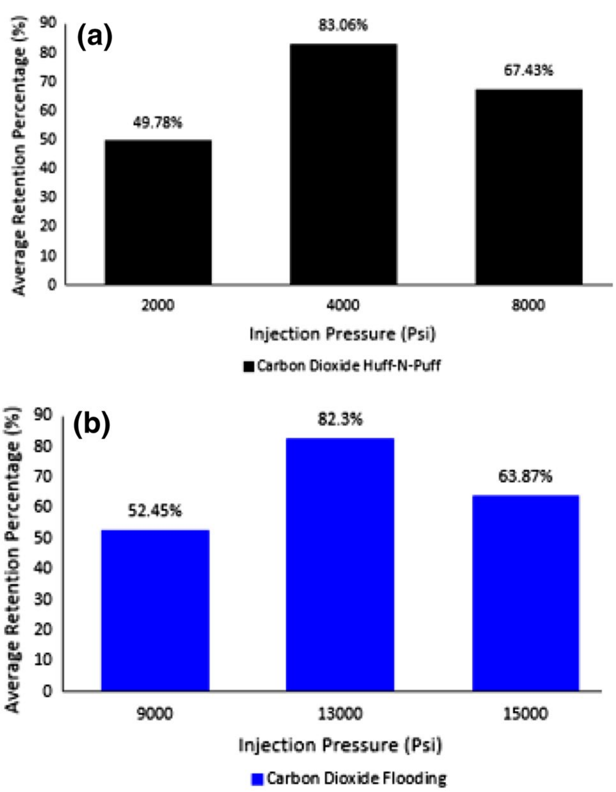


Fig. 10 Impact of injection pressure on CO_2 retention in WCSB Alberta tight oil reservoir: **a** CO_2 Huff-N-Puff, **b** CO_2 flooding

Tight gas reservoir: CO_2 huff-n-puff and flooding process performances

The reservoir simulation was even applied to the Alberta tight gas reservoir using CMG-GEM reservoir simulation software package. The same reservoir gridding parameters that used for the Alberta tight oil reservoir has been employed in this tight gas model also. The only difference is the reservoir fluid, in the previous case it was oil, but in this case, it is a gas. Also, the porosity and permeability values are 11.5% and 0.00002 mD in the Alberta tight gas reservoir model. Additionally, the fracture half-length and spacing are 325 ft and 42 ft for this tight gas reservoir model. Like the Alberta tight gas reservoir, the model was operated to run for 30 years. Subsequently, the hysteresis trapping of CO_2 was obtained from the simulation outcomes and the retention percentage was calculated using the Eq. 1, given by Olea (2015). Table 2 shows the CO_2 storage results in WCSB Alberta tight gas reservoir for both CO_2 HNF and FDG cases. It can be seen from Table 2 that in the first year there were no CO_2 trapped by the hysteresis in both carbon dioxide HNF and FDG process, because of elevated reservoir pressure that automatically displaces the reservoir fluid (gas) out of the tight formation. Also in this scenario, the CO_2 retention means the amount of carbon dioxide has been successfully filled in the reservoir.

For the CO_2 HNF scenario, in the year 2 the injection pressure was designed to 2500 psi and the injection mass is 45 MSCF/day and the carbon dioxide retained amount is 7.038 MSCF. While, in the CO_2 FDG case, the second year with 9400 Psi of injection pressure, 36.33 MSCF was retained. In the starting year, like in the Alberta tight oil reservoir the CO_2 flooding performance is better than the CO_2 huff-n-puff. Nevertheless, during the following years, a linear and stabilized carbon dioxide retention by hysteresis growth rate was observed in both injection scenarios. Hence, at the end of year 10 of carbon dioxide flooding case, 159.978 MSCF of CO_2 retention was recorded and 36.1575 MSCF has been recorded in the CO_2 huff-n-puff case. Furthermore, it can be clearly seen from Table 2 that even both cases in the second decade that is from the year 11 to 20, contributed in the stabilization of the CO_2 retentions and

Table 2 CO_2 storage results in WCSB Alberta tight gas reservoir for both Huff-N-Puff and flooding processes

WCSB Alberta tight gas reservoir							
CO_2 Huff-N-Puff p				CO_2 flooding process			
Year	Injection pressure (psi)	Injection rate (MSCF/day)	CO_2 trapped by hysteresis (MSCF)	Year	Injection pressure (psi)	Injection rate (MSCF/day)	CO_2 trapped by hysteresis (MSCF)
1	0	0	0	1	0	0	0
2	2500	45	7.038	2	9400	210	36.33
3	2500	45	11.7	3	9400	210	46.2
4	2500	45	13.5	4	9400	210	58.8
5	2500	45	18.9	5	9400	210	75.6
6	2500	45	26.1	6	9400	210	115.5
7	2500	45	29.25	7	9400	210	126
8	2500	45	32.4	8	9400	210	144.9
9	2500	45	35.1	9	9400	210	155.4
10	2500	45	36.1575	10	9400	210	159.978
11	4800	120	96.42	11	13,600	430	318.114
12	4800	120	96.42	12	13,600	430	333.766
13	4800	120	96.42	13	13,600	430	333.766
14	4800	120	96.42	14	13,600	430	333.766
15	4800	120	103.2	15	13,600	430	333.766
16	4800	120	105.6	16	13,600	430	333.766
17	4800	120	110.4	17	13,600	430	361.12
18	4800	120	112.248	18	13,600	430	383.775
19	4800	120	112.98	19	13,600	430	394.525
20	4800	120	114.312	20	13,600	430	400.115
21	6300	356	194.9812	21	15,200	620	303.304
22	6300	356	200.0364	22	15,200	620	326.74
23	6300	356	221.254	23	15,200	620	371.566
24	6300	356	235.9212	24	15,200	620	422.096
25	6300	356	261.9448	25	15,200	620	472.75
26	6300	356	268.6732	26	15,200	620	490.482
27	6300	356	274.5472	27	15,200	620	505.238
28	6300	356	287.4344	28	15,200	620	509.578
29	6300	356	297.7584	29	15,200	620	516.77
30	6300	356	304.2376	30	15,200	620	524.21

also, this same pattern closely continued for the last 10 consecutive years (Year 21–30). At the end of completion year that is the year 30, a CO_2 HNF process in tight gas reservoirs has retained 304.2376 MSCF and 524.21 MSCF has been retained with the CO_2 Flooding process. It is emphasized that the CO_2 flooding contributed in higher carbon dioxide retention than CO_2 HNF process in the Alberta tight gas reservoir. But, with regards to CO_2 storage in these formations, the caprock surface morphology determines this supercritical fluid storage capacity and security (Ahmadinia et al. 2019; Nilsen et al. 2012).

There is a successful accomplishment of CO_2 accumulation in the tight gas reservoir, presented in Table 2. Figure 11 shows the actual carbon dioxide retention percentage calculations in the Alberta tight gas reservoirs. Like in the Alberta tight oil case, the tight gas case also displayed a sinusoidal and sporadic behavior on CO_2 retention. The first decade CO_2 retention performance was excellent and soaring, but in the second decade the supercritical fluid retention is stabilized. There is deterioration in the retention performance during the start of the third decade and then climbed linearly. Overall, this sinusoidal and sporadic behavior is attributed to the frequent well closure due to CO_2 soaking, number of cycles, injection time and mass. Therefore, due to these constraints, it is very difficult to locate or indicate the sweet spot on where the desirable (maximum) CO_2 retention can be obtained (Pranesh et al. 2018). Whatsoever, more than 80% of carbon dioxide retention has been achieved in the Alberta tight gas reservoir also. Furthermore, Shariatipour et al. (2014) stated that plume migration and penetration

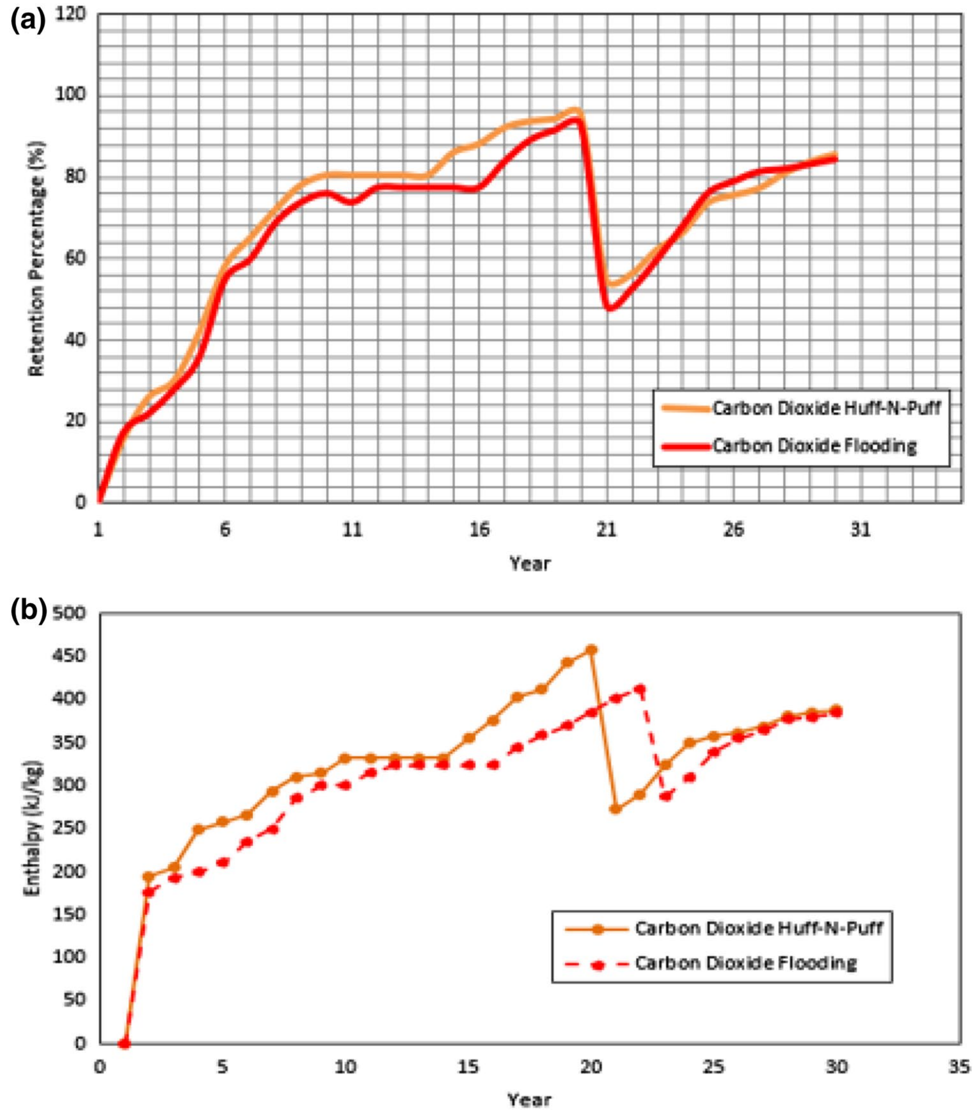


Fig. 11 **a** CO_2 retention estimation in WCSB Alberta tight gas reservoir, **b** Subsurface CO_2 retention enthalpy in WCSB Alberta tight gas reservoir

is a serious and common problem in the subsurface CO_2 sequestration. But, due to the sporadic and sinusoidal CO_2 retentions in the tight gas reservoirs, the plume penetration is controlled. Moreover, in the ultra-low permeability formations like in the Alberta formations of the WCSB, there is no possibility of plume penetration and migration in other stratigraphic layers. Additionally, it was proved that CO_2 adsorption on shales and rocks can enhance the methane recovery and CO_2 storage as well (Rani et al. 2019). Under this mechanism a maximum of 90% carbon dioxide storage has been achieved and also, 16% methane recovery has been accomplished (Mohangheghian et al. 2019). On the whole, the ultimate goal in this work is to sequestrate the CO_2 in the tight formations and higher productivity of EOGR.

Figure 11b shows the subsurface CO_2 retention enthalpy in WCSB Alberta tight gas reservoir. Also, in this case, it is observed that the enthalpy values are similar to that of the CO_2 retention values. This influences and triggers the enthalpy or supercritical heat transfer in tight gas reservoir. Actually, the CO_2 enthalpy was obtained from computational fluid dynamics (CFD) software package. The reservoir simulation model data were exported to the CFD ANSYS Fluent model and subsequently, the enthalpy curves were obtained. This process methodology is even applicable to the Alberta tight oil reservoir. Moreover, the supercritical CO_2 in tight gas reservoirs, especially in sandstone formations can transform to a CO_2 fracturing fluid and consequently, this can create new permeable and fracture spaces, which overall can yield enormous enhanced gas recovery (Dai et al. 2018b; Gao and Li 2016).

Figure 12 shows the impact of injection pressure on CO_2 retention in WCSB Alberta tight gas reservoir for CO_2 HNF and FDG scenarios. Like in the Alberta tight oil reservoir, the average retention values in the Alberta tight gas reservoir were calculated for each decade for carbon dioxide HNF and FDG scenarios. It can be seen from

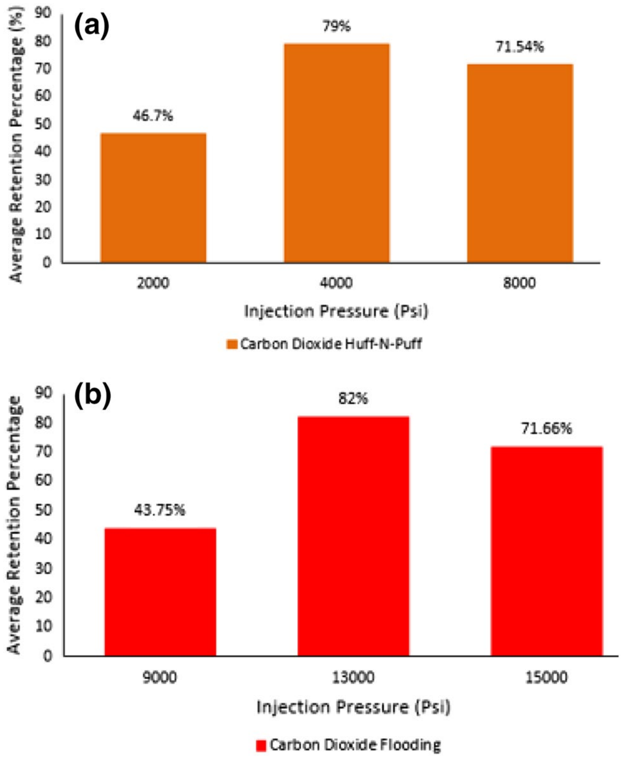


Fig. 12 Impact of injection pressure on CO_2 retention in WCSB Alberta tight gas reservoir: **a** CO_2 Huff-N-Puff, **b** CO_2 flooding

Fig. 12a that for the CO_2 huff-n-puff case 46.7%, 79%, and 71.54% of CO_2 retention has been acquired for the 2500 Psi, 4800 Psi, and 6300 Psi injection pressures. For 20 years, there is a linear rise in the CO_2 retention rate in the Alberta gas reservoir using CO_2 huff-n-puff and at the last decade the growth deteriorated to 71.54%. CO_2 retention growth plummet of 7.46% was observed and this could be due to the gas adsorption on tight rocks and new pore spaces has been created due to higher reservoir rock enthalpy and supercritical heat transfer. The creation of new pores in the Alberta tight gas formation at WCSB has generated the residual trapping of CO_2, where the plume migration and penetration can be controlled and restricted. Most commonly, pores adsorb gas and enhance its storage volume, and thereby, increasing the space for CO_2 and gas storage (reservoir fluid-methane). As this mechanism was reported in the Devonian Duvernay Shale at Western Canada Sedimentary Basin (Wang et al. 2018). Furthermore, a similar pattern was observed for the CO_2 flooding scenario, seen in Fig. 12b. But, here 10.34% drop in CO_2 retention was recorded in the third decade. By comparing with this with the CO_2 HNF case only a 2.88% decline of carbon dioxide was observed. Overall, in the Alberta tight gas reservoir at WCSB this CO_2 decline in both injection cases has no serious effect.

Conclusions

First and foremost, the geology of the Western Canadian Sedimentary Basin (WCSB) was reviewed and critically examined. Its geological features offer a safe and reliable place for long time storage of the supercritical carbon dioxide and besides, tight oil and gas fields in the Alberta Province at WCSB exhibits a good storage location through the retention mechanism during CO_2 EOGR process. Therefore, based on the modelling outcomes, the following major conclusions can be made:

(a) CO_2 retention in the WCSB tight oil and gas reservoirs indicated sinusoidal and sporadic behavior. However, in four cases more than 80% carbon dioxide retention was achieved and consequently, the oil and gas recovery rates has been improved. In tight oil reservoirs, the subsurface enthalpy that is the heat distribution and transfer during CO_2 retention was also exhibited a sinusoidal and sporadic behavior. In tight oil reservoirs, it can be implicated that the subsurface CO_2 storage and enthalpy are directly proportional. Most importantly, it should be noted that even similar behavior was recorded for the Alberta tight gas reservoirs. But in this case, there is a slight variation in the retention and enthalpy profiles and this can be attributed to gas adsorption on tight rocks.

(b) There is a rivalry between CO_2 huff-n-puff and flooding processes in Alberta oil reservoirs in terms of yielding maximum percentage of retention. Even though they contributed a sinusoidal and sporadic growth with respect to increasing year (DMU) there is a conspicuous rivalry between the two methods of carbon dioxide injection process on higher CO_2 retention percentage contribution. Furthermore, the same rivalry was even observed for an enthalpy profile in the Alberta oil reservoir. In the case of gas reservoirs, initially, CO_2 huff-n-puff contributed in a higher percentage of retention and the CO_2 flooding process has also made close contribution in enhancing the retention rates in the gas reservoir. Later, on the last consecutive years the CO_2 flooding process has overtaken and levelled the huff-n-puff process on maximizing the supercritical fluid retention rates. Subsequently, the gas reservoir enthalpy during CO_2 retention showed a similar behavior.

(c) Injection pressure was found to be the most dominating factor on CO_2 retention in oil and gas reservoirs. In both huff-n-puff and flooding methods the retention percentage estimates increases with respect to elevating injection pressures. Because, the injection pressure values in these methods is different. Moreover, in oil reservoirs high yield can be obtained in huff-n-puff process due to its reservoir and supercritical fluids soaking period as a function of temperature and pressure. Even in tight gas reservoirs, the impacts of temperature, pressure, and volume (TPV) determine the gas recovery rate and storage as well. Most importantly, the CO_2 plume has been restricted to due tight (less porous) formations and this it ensures the storage safety and assurance of leakage prevention. Actually, reservoir hysteresis properties can reduce the plume migration during CO_2 injection and storage (Pham et al. 2011). Therefore, on the basis of the above modelling results, it can be explicitly stated that the Western Canada Sedimentary Basin exhibits an attractive and secure storage sites for CO_2 sequestration and subsurface fuel (reservoir fluids) recovery as well. This is all possible due to the basin's complex and tight geological features.

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Compliance with ethical standards

Conflict of interest The authors declare no conflict of interest.

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