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Numerical simulation of Water-alternating-gas Process for Optimizing EOR and Carbon Storage

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Abstract

As concerns around global warming increase, carbon capture, utilization and geological storage (CCUS) is a promising way to reduce the emissions of the anthropogenic CO_2 into the atmosphere. Of those, sequestering the CO_2 into depleted hydrocarbon reservoirs with associated enhanced oil recovery is the most achievable approach under current economic constraints since it increases recovery of existing oil reserves, and bridges the gap between regional-scale CO_2 capture and geologic sequestration. The Upper Devonian fluvial sandstone reservoirs in Jacksonburg-Stringtown oil field in West Virginia, which have produced over 22 million barrels of oil since 1895, is an ideal candidate for CO_2 sequestration coupled with EOR. This work illustrates an example of CCUS, in which CO_2 is simultaneously sequestered and oil recovery enhanced in a depleted oil reservoir by water alternating gas (WAG) method. Three mechanisms for CO_2 storage including structural/stratigraphic trapping, dissolution trapping and residual trapping are considered. This model is based on a highly detailed geological model constructed based on existing legacy geological data from the field. A composition model of 0.4 PVI of water injected before WAG process is considered as a benchmark for this study. The results of numerical simulation show that over 26 years of WAG injection, oil recovery increased from 0.16% to 1.9% due to various injection strategies. WAG injection rate, injection time ratio and cycle period play important roles in the storage CO_2. As a conclusion, this research constructs and validates a basic workflow for CO_2 storage and CO_2-EOR that can be applied to other super-mature oil fields, which have abundant conventional legacy data and limited high-quality data.

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Keywords: Water Alternating Gas(WAG), Carbon Capture Utilization and Geological Storage(CCUS), CO_2-Enhanced Oil Recovery(CO_2-EOR), CO_2 Trapping Mechanisms

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1. Introduction

The concentration of carbon dioxide (CO_2) in atmosphere increase significantly since the industrial revolution, which is caused by tremendous emissions of anthropogenic CO_2 produced from industrial sources, fossil fuel combustion and land-use change [1,2]. The idea that global warming is mainly caused by anthropogenic CO_2 emissions has been widely accepted [3,4]. Now, it is impossible to replace fossil fuel based energy produced methods with more sustainable resources [4]. Geological capture, utilization, and storage (CCUS) of CO_2 in depleted oil and gas reservoirs is one promising method to reduce greenhouse gas emissions released into the atmosphere to mitigate the effects of anthropogenic climate change while enhancing oil recovery (EOR) and extending the life of the hydrocarbon reservoir [5,6,7]. Moreover, this method also takes numerous advantages because its economic incentives exceed any other sequestration options, such as saline aquifers, and unmineable coal seams [6] Therefore, CCUS coupled with EOR is an economic approach to demonstrate of commercial-scale injection and storage of anthropogenic CO_2.

Since the first viable CO_2 commercial EOR applications started in 1972 in the Kelly-Snyder oil field, CO_2-EOR has been utilized for over 46 years [8]. In 2014, 136 CO_2-EOR projects were underway in the United State and producing approximately 300,000 barrels of oil per day (BOPD) [9]. Sophisticated CO_2-EOR technology makes CO_2 sequestration in depleted oil and gas reservoir more widely than in saline aquifers and unmineable coal seams.

A geological media must have such properties such as capacity, injectivity, and confinement in terms of safety and long-term CO_2 storage [10]. Carbon dioxide can be stored in a geological media by various means through a variety of physical and chemical trapping mechanisms [11] (Table 1). Physical trapping of CO_2 occurs when CO_2 is immobilized as a free gas or supercritical fluid, and as a process, it depends on the available storage volume [12]. Chemical trapping of CO_2 occurs when CO_2 contact with any materials in underground storage sites. As Table 1 listed, structural/stratigraphic trapping mechanisms are important parts in the storage of CO_2 in a depleted hydrocarbon reservoir. The integrity of the cap-rock is vital to the prevention of upward movement of supercritical CO_2 towards the surface [13]. Residual trapping, first proposed by Kummar et al.(2005) [14], means the CO_2 left behind as residual or droplets in the pore spaces when the supercritical CO_2 is injected into the reservoir [15]. The solubility trapping means that CO_2 dissolves into the aqueous and oil phase in the reservoir, by which not only oil viscosity will decrease as CO_2 miscible with oil but also brine can dissolve a large amount of CO_2. The mineral trapping means that when CO_2 dissolves in water it forms a weak carbonic acid, which can react with the minerals in the surrounding rock to form solid carbonate minerals. This trapping process will take a very long time. Due to the process of mineral trapping taking almost thousands of years, it is ignored in this research. The calculation process of theoretical and effective storage capacity just takes physical and solubility trapping into consideration.

This paper presents a small scale compositional numerical modeling of CO_2 storage capacity and increases oil recovery as a function of different trapping mechanisms within the simplified box-shaped fluid model, which is cut from the true geological model [16]. Lots of the remaining oil in places has not been recovered under primary and secondary process in Jacksonburg-Stringtown mature oil fields. The original oil in place in Jacksonburg-Stringtown is 88 MMBL, and around 22 MMBL of oil has been produced until now, thus the current oil recovery factor is around 25%. It also means that more than 55 million-barrel oil (MMBO) of residual oil is stranded in Jacksonburg-Stringtown oil field and 5 million to 11 million barrels oil (MMBO) may be recoverable from CO2-EOR. The targeted Gordon Stray sandstone reservoir presents opportunities both to enhance oil recovery and sequester a large portion of injected CO_2 into the underground reservoir. Several trapping mechanisms are discussed include structural/stratigraphic, solubility (in water and oil) and residual trapping. This study constructs and validates a basic workflow for CO_2 storage and CO_2-EOR that can be applied to other super-mature oil fields, which have abundant conventional legacy data and limited high-quality data.

Table 1. CO_2 geological storage trapping mechanisms

Storage Mechanism	Trapping Type
Physics Storage	Structural Trapping
	Stratigraphic Trapping
	Residual Trapping
Chemistry Storage	Solubility Trapping
	Mineral Trapping

2. Methodology

2.1 Reservoir Characterization

The Gordon Stray formation within the Jacksonburg-Stringtown field is located at depths ranging from 2800-3100 ft. (850-950 m) with a total thickness of between 15-75 ft. [17]. The average depth is 3000 ft. and entire average thickness is approximately 50 ft. The reservoir area shape is like an inverted cone, which is wider in the north, narrower in the south. The relatively high-permeability and high-porosity Lower Gordon Stray unite is the injection target reservoir, with the thickness between of 10-40 ft. The overlying cap-rock is consisting of a series of inter-bed sandstone and shale which have been proved to be correlative throughout the whole field [18]. The simple semi-variograms (Fig.1) for porosity and permeability are calculated in vertical direction, and the results are fitted based on exponential function.

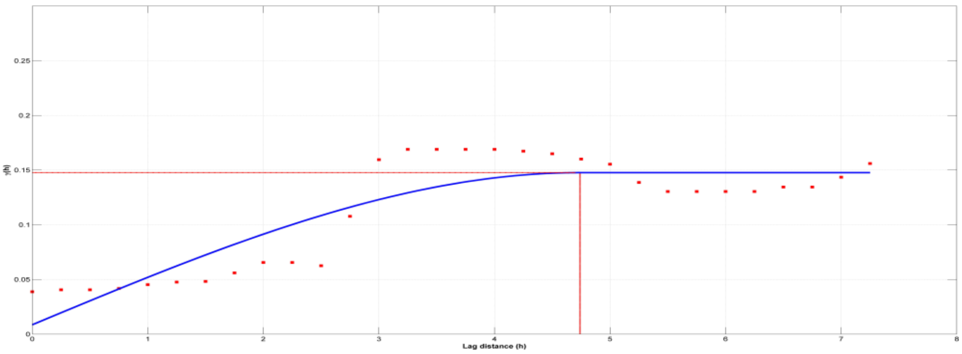


Fig. 1 Semi-variograms for porosity in vertical direction

Based on the water-oil experimental relative permeability data reported by Gil [19], the relative permeability curves for Gordon Stray formation was shown in Fig.2a. The blue dots represent experimental water-oil relative permeability data, while the red line represents the fitted water-oil relative permeability data, which is calculated based on the Parker's (1987) function. Because the CO_2 injection is related to gas injection, then residual trapping is very important storage mechanism, thus gas-liquid relative permeability is very important. Here, we employed Corey's (1954) [20] expression, the gas-liquid relative permeability curves are shown in Fig.2b.

2.2 Reservoir Model Description

To per-characterize and per-evaluate the CO_2 storage capacity in Jacksonburg-Stringtown depleted oil reservoir, a heterogeneous box-shaped model of 31×31×5=4805 grids system with grid block dimensions of 1240ft×1240ft×20ft (Fig.3). Permeability, porosity distribution, and the location of producer and injector wells with five spot configurations are depicted in Fig.3. The target injection reservoir thickness is 16 ft. with an overlying seal which is

4 ft. and forms the first layer of the model. The seal layer has low permeability and high capillary entry pressure to enable CO_2 trapping. Reservoir porosity and horizontal permeability are generated based on the horizontal and vertical semi-variograms by using commercial software (Petrel 2012), and the final results were transported into commercial composition reservoir simulation software (CMG GEM 2012). Table 2 shows the input parameters for the base case.

Water and gas injection rate are constant in each model, but they are various in the different model in different scenarios. For a constant injection rate, the injected volume of water and gas thus depends on injection time. Here, injected time of water to that of CO_2 in one cycle is named as WAG time ratio (T_{WAG}) [21]. For instance, a WAG time ratio of 1:1 represents one-unit time duration of water continuous with one-unit time duration of gas during a cycle. The WAG scheme is designed to identify the best WAG time ratio. The WAG ratio is defined as:

$$T\_WAG = T\_CO2/T\_Water$$

where T_{CO2} is the CO_2 injection time (days); T_{Water} is the water injection time (days).

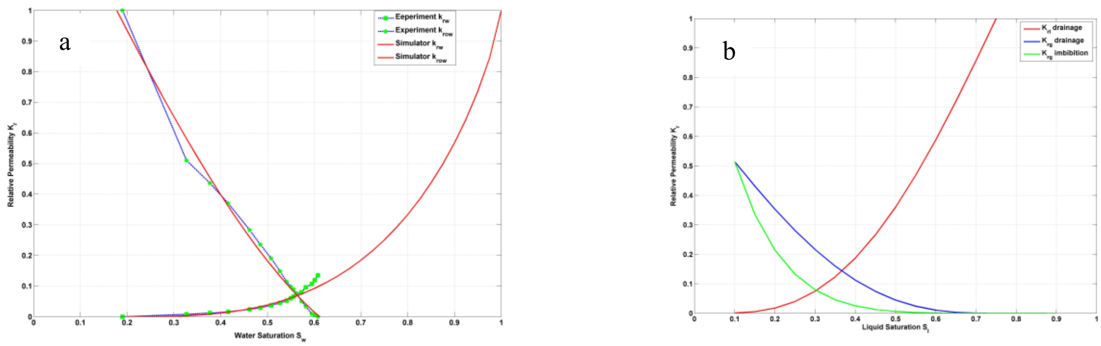


Fig. 2 (a) water-oil relative permeability calculated based one experiment and simulator; (b)gas-liquid relative permeability curves.

Table 2: Basic parameters of reservoir simulation model

Parameters	Values
L×W×H (ft.)	1240×1240×20
$N_x\times N_y\times N_z$	31×31×5
$D_x\times D_y\times D_z$	40×40×4
Pore Volume (ft^3)	3.15×10^6
K(mD)	12
Phi(%)	0.99
Reservoir Depth (ft.)	2912
Reference Pressure @2882 psi	1000
Initial Reservoir Temperature (F)	82
k_V/k_h	0.1
Rock Compressibility (1/psi)	3.999×10^{-6}

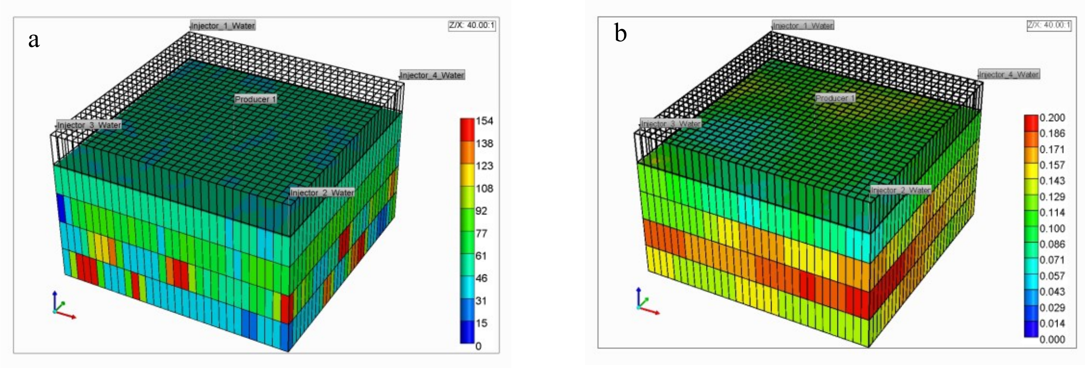
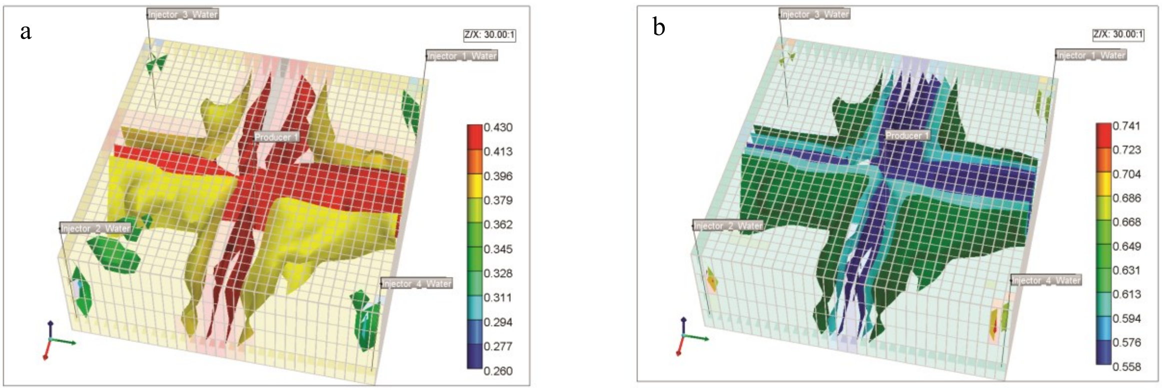


Fig. 3: The 3D five-spot well pattern reservoir model, (a) permeability model, (b) porosity model. The permeability and porosity top layer (cap-rock) are ultra-low, thus it is nor displayed in this figure.

2.3 CO_2-EOR Schemes

Numerical simulations are performed using the compositional CMG GEM software (CMG 2012). All simulations were performed with a fixed production-well bottom-hole pressure that was 200 psia less than initial pressure. 0.4 PVI of water was injected at reservoir temperature prior EOR process to represent the secondary oil recovery using water-flooding. As Fig. 4(a), (b) and (c) shown, the water saturation, oil saturation, and pressure distribution are not symmetrical because of reservoir heterogeneity. Fig. 4(d) shows that waterflood oil recovery factor is almost 26% when 0.4 PVI of water was injected. This situation is really close to Jacksonburg-Stringtown oil field, which also has 25% oil recovery. After 6 years of injection, wells are completely shut-in and stored CO_2 is monitored for additional 200 years as a function of various storage mechanisms. The entire duration of WAG-EOR was from January 2010 to January 2216.



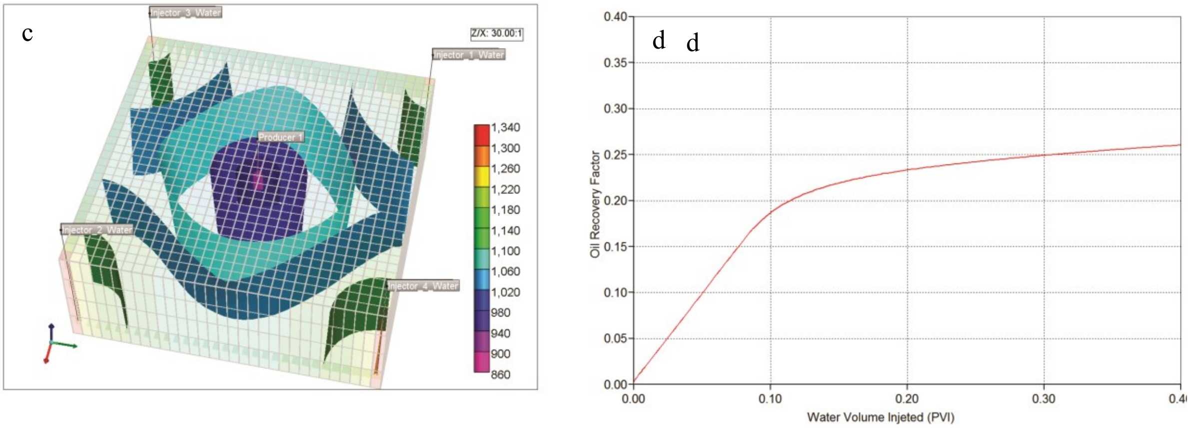


Fig. 4: (a)water saturation, (b)oil saturation, (c)reservoir pressure and (d) primary oil recovery factor after 0.4 PVI of water was injected. This is the initial model for further EOR scenarios.

3. Result

3.1 Oil Recovery

As we all know that, CO_2 injection into the reservoir is an effective EOR method, which can enhance the final hydrocarbon (HC) recovery of the reservoir [22]. However, different injection rates and injection schemes will have various influence for the final HC recovery factors. By combining the best production and injection parameters, the sweep efficiency should be maximized and highest oil recovery should be achieved simultaneously. Fig.5 illustrates the oil recovery factors obtained at different WAG schemes after 6 years of WAG process. As Fig. 5A shows, the CO_2-WAG cycle is one year period, and with increasing the injection rate, the oil recovery increases (Fig. 5A_1), and with increasing the WAG time ratio, the oil recovery decreases (Fig. 5A_2). The same situation happens at different WAG-cycle time period scenarios, and the oil recovery factory also varies for different WAG time cycle, as shown in shown in Fig. 5(B,C,D). When water is injected, water is forced to pass through the porous media, and sweep the oil ahead to the producer wells. After water injection, CO_2 was injected into the reservoir in miscibility condition, not only pushes the oil to the producer well, but also mixes itself into the oil which reduces the oil viscosity and its residual saturation [23,24].

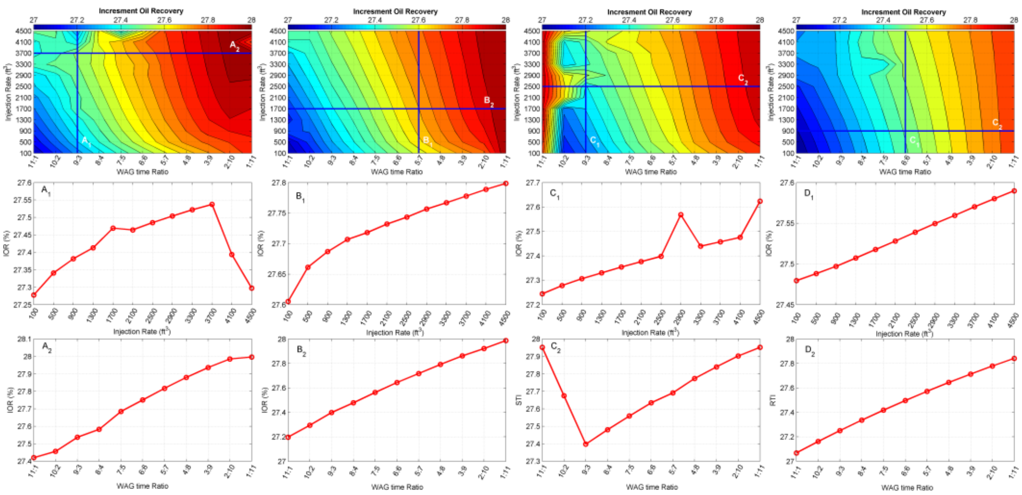


Fig. 5: Increment oil recovery with different WAG cycle period, WAG time ratio, and injection rate. (A)(B)(C)(D) represents the 1 year, 2 years, 3 years and 6 years injection cycle period. A_1 and A_2 indicate the cross-section for corresponding Figure (A)

3.2 Effect of various operating parameters on CO_2 storage efficiency

Changes in CO_2 and water cycling in a CO_2 flood can affect both the CO2-EOR performance and the amount of CO_2 stored within the reservoir under different storage mechanisms. With same WAG time ratio and same injection rate, WAG cycle has significant impact on the CO_2 -EOR oil recovery factor, which always ranges from 27% to 28%, it is, therefore, necessary to use optimum injection WAG cycle period to ensure higher oil recovery factor.

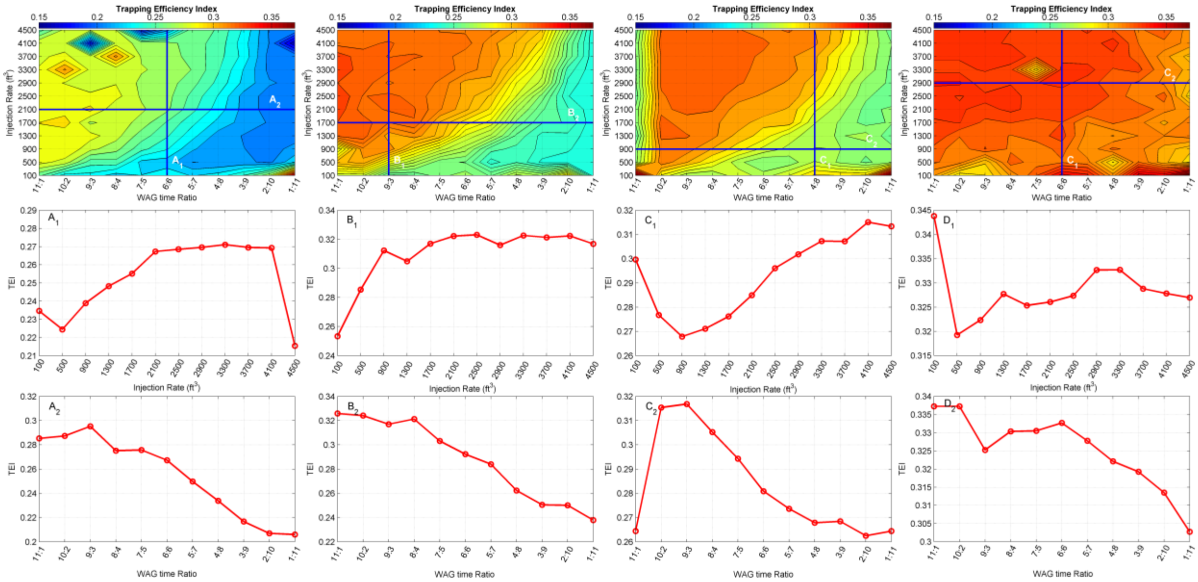


Fig. 6: Trapping efficiency index for different CO2-EOR schemes with 1 year, 2 years, 3 years and 6 years injection period.

4. Conclusions

This work studies the different storage mechanisms contributing to CO_2 storage within a depleted oil reservoir. It consists of the comparative study of different WAG injection process for the simplified reservoir model. Based on the reservoir simulation results, some important conclusions are derived from implementation of WAG process. The WAG (water alternating gas) process can increase the sweep coefficient and decrease the mobility ratio between water and oil phases and improves the total recovery of the reservoir. The WAG cycle period in WAG injection process plays critical roles in the recovery of oil from the reservoir. In terms of oil recovery, high WAG time ratio is better than low WAG time ratio, however, it will be totally reverse in terms of CO2 storage. As results show, the high CO_2 injection rate indeed increases the oil recovery.

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