https://doi.org/10.53656/nat2024-3-4.02

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EVALUATING THE EFFICACY OF WATER ALTERNATING GAS INJECTION TECHNIQUE IN THE UPPER JURASSIC HYDROCARBON RESERVOIRS, CONSIDERING SATURATION PRESSURE

Meil Hofmann[1)], Sudad H. Al-Obaidi[2)], Wang J. Chang[3)]
[1,2)]*Mining University (Russia)*
[3)]*University of Xidian (China)*

Abstract. A tertiary method of enhanced oil recovery (EOR) based on the water-gas alternating injection process (WG) is examined in this article based on the ratio between saturation pressure and reservoir pressure. A hydrodynamic simulation of the WAG process was carried out using TEMPEST MORE software (version 7,1). Many hydrocarbon fields worldwide are currently experiencing declining production rates. However, by utilizing advanced technologies like alternate injection of water and associated petroleum gas, the final oil recovery factor (RF) can be significantly increased. To ensure successful water injection experiments in real fields, it is crucial to consider the ratio of saturation and reservoir pressures during injection. Any negligence in this regard can lead to failure of the experiments aimed at enhancing oil recovery through WAG application.

The research examines two variations of reservoir system models with certainty. In the initial model, the saturation pressure is lower than the reservoir pressure, signifying an under-saturated state of the reservoir system containing dissolved gas. Consequently, when accompanying petroleum gas is introduced, it mixes with oil at precise thermobaric conditions. According to the second model, the reservoir is saturated with gas at a saturation pressure equivalent to the formation pressure. A thorough assessment indicates that the success of water alternating gas injection (WAG) is heavily influenced by the initial state of the reservoir. In situations where the reservoir is already saturated with gas, implementing water-gas stimulation may be ineffective as gas breakthroughs may occur rapidly. However, implementing WAG in saturated reservoirs can lead to a 1 – 8% rise in overall oil production, observable within 3 – 4 years, depending on the timing after waterflooding. Simultaneously, in the case of reservoirs with a low saturation pressure, which exhibits an undersaturated reservoir system, the implementation of water alternating gas injection can be seen as a viable approach for enhancing oil recovery. WAG is a proven method that confidently increases oil recovery up to 10% in undersaturated reservoirs compared to conventional waterflooding.

Keywords: WAG, Waterflooding; Saturation pressure; Cumulative oil production; EOR

1. Introduction

Over the past few years, the use of water alternating gas injection (WAG) has become more prevalent in global operations as a means of boosting the production of challenging oil reserves (Liao et al. 2022; Afzali, Rezaei & Zendehboudi 2018; Belazreg & Mahmood 2020). This innovative technology is being utilized to enhance oil recovery from these reserves. Implementing water alternating gas injection method in the studied oil and gas region of Western Siberia has the potential to significantly increase the oil recovery factor. Renowned for its vast natural gas reserves, this region boasts numerous fields that possess the necessary geological and physical characteristics for the successful application of this approach (Bhadran et al 2019; Al-Obaidi 2021; Sorokin et al. 2021). The article focuses on the technique of alternating injections of associated petroleum gas and water, which is better suited for the geological, physical, and geographical characteristics of Western Siberia. This method, known as WAG, increases both the coverage coefficient and the displacement coefficient (Al-Shargabi 2022; Smirnov & Al-Obaidi 2008; Verma 2015). The alternate injection of working agents involves injecting gas and water in small alternating slugs, which is typically 5% or less of the initial oil-saturated pore volume.

To successfully displace oil using injected agents, it is crucial to ensure mutual miscibility between the injected gas and the fluid present in the formation. This can be achieved by closely adhering to specific thermobaric conditions and having a deep understanding of the saturation state of the formation system during the WAG process (Wojnicki et al. 2022; Al-Obaidi & Khalaf 2019; Panahov, Abbasov & Jiang 2021). By confidently following these guidelines, effective displacement of oil can be accomplished.

After extensively evaluating relevant literature sources (Ma & James 2022; Liao et al. 2022; Abdullah & Hasan 2021), it has been established that the application of water alternating gas (WAG) injection in oil reservoirs frequently neglects a crucial factor: the saturation pressure to reservoir pressure ratio during stimulation initiatives. Moreover, there is a significant knowledge gap regarding the ideal amount and timeframe for injection of displacement agents, as well as the most suitable stage of development for incorporating WAG.

This study explores the potential of implementing WAG as a tertiary method to enhance oil recovery in Upper Jurassic deposits. These formations show promise for WAG application, supported by limited field trials and published data from hydrodynamic simulations specific to Western Siberia (Bello et al. 2024; Shandrygin

& Lutfullin 2008; Berman 2023; Al-Obaidi 2016). Notably, the Nizhnevartovsk and Surgut arches contain Upper Jurassic reservoirs with a significant difference between saturation and formation pressures, indicating predominantly undersaturated gas systems (Liu et al. 2022; Chen et al. 2023).

During the 2006 – 2007 in the Novogodny field, it was discovered that water-gas injection was unsuccessful in the later phases of field development. This was because the reservoir system had undergone significant changes from its original state when the pilot project for water-gas stimulation was implemented. The operational wells had 80 – 90% water cut, while the initial saturation of the reservoir system was evident through the saturation pressure being nearly identical to the reservoir pressure (Al-Obaidi & Chang 2023).

In order to conduct a successful pilot industrial work on WAG, it is crucial to carefully consider specific criteria when choosing an object. One important factor to consider is the level of heterogeneity, as a high degree of heterogeneity can lead to decreased efficiency of water injection due to rapid breakthroughs of displacing agents in highly permeable layers (Adegbite & Al-Shalabi 2022; Xue, Liu & Zhang 2023; Matkivskyi & Burachok 2022). Additionally, reservoir temperature is a key consideration when selecting candidate wells for WAG. When the temperature exceeds 70 °C, the efficiency of oil recovery can greatly improve due to the removal of residual oil components by the injected gas (Rudyk, Spirov & Tyrovolas 2018; Patkin & Al-Obaidi 2001). The prevention of crystalline hydrate formation, particularly in the reservoir, is of utmost importance for WAG. This requires maintaining a higher temperature than the hydrate formation temperature. Additionally, the reservoir system must be undersaturated with hydrocarbon gas, with a saturation pressure that is 25 – 50% lower than the reservoir pressure (Duan et al. 2023; Pourhadi & Fath 2020). This study aims to analyse the impact of saturation pressure to reservoir pressure ratio on the effectiveness of water alternating gas stimulation. The research will focus on the Upper Jurassic reservoirs in Western Siberia and the findings can be adapted for use with sediments from similar environmental conditions.

2. Methodology and materials

To simulate the impact of the reservoir system model on the efficiency of WAG, the Tempest (Khan, Amin & Madden 2013; Hofmann, Al-Obaidi & Khalaf 2022; Vinogradov et al. 2015) software package was used. Within the software, a comprehensive hydrodynamic model was constructed for the Upper Jurassic reservoir, with its lithology being characterized by alternating layers of clays and sandstones. The thickness of the reservoir was 8.5 meters and it was situated at a depth of 2600 meters. By examining the mean weighted values of key parameters from Upper Jurassic formations in the Nizhnevartovsk arch, the predominant geological and physical features of the deposit were determined. These parameters consist of a porosity of 16%, a permeability of 0.025 μm^2, a reservoir temperature of 91°C, and an initial reservoir pressure of 26 *MPa*. Furthermore, the *PVT* (pressure, volume and temperature) characteristics of both oil and gas were identified, with an initial oil saturation of 63% and an oil density of 843 kg/m^3 at surface conditions. After extensive planning, the model was meticulously crafted to incorporate the relative phase permeabilities (Kr) and capillary pressures. These parameters were acquired from generalized relationships observed in over 30 hydrocarbon fields within Upper Jurassic formations (Kontorovich et al. 2024; Novikov et al. 2023). Utilizing an inverted five-point development system with a well spacing of 500 meters, the model boasts a generous size of 100x100x17 cells, guaranteeing its thoroughness and precision.

The model was evaluated in two versions. The initial situation involves a saturation pressure of 12 MPa, which is lower than the reservoir pressure, indicating an undersaturated reservoir with gas dissolved in the oil. In this case, the addition of associated petroleum gas would result in the gas dissolving in the oil under specific thermobaric conditions (Pavlova et al. 2022; Al-Obaidi & Khalaf 2023). The second scenario assumes the reservoir is completely saturated with gas at a saturation pressure equal to the formation pressure of 26 MPa.

3. Results and discussions

During the initial phase, a homogenous model was utilized to compute various possibilities involving varying proportions of displacement agents injected, in terms of both time and quantity (Table 1).

Table 1. Modelling water alternating gas injection (WAG) on a homogeneous reservoir with various implementation options

No.	Water/gas injection days ratio	Injection ratio of water (m^3/day) to gas (1000m^3/day)	Cumulative production of Oil 1000 t	Operating time of wells before depletion
Saturated reservoir				
1	60/60	400–200	29,60	Nine months
2	60/60	400–100	24,99	One year
3	90/30	400–200	27,21	One year
4	90/30	400–100	29,30	Three years
5	105/15	400–100	32,23	Three and a half years
Undersaturated reservoir				
1	60/60	400–200	55,39	Two years
2	60/60	400–100	56,14	Two years
3	90/30	400–200	63,99	Four years
4	90/30	400–100	75,11	Nine years
5	105/15	400–200	75,21	Nine years
6	105/15	400–80	72,42	Ten years

The cumulative production of a low saturation pressure reservoir is twice as high as that of a saturated gas reservoir. For further analysis of the WAG, the optimal option was selected with the following parameters: the ratio of injectivity limitations: water – 400 m^3/day, gas – 100 thousand m^3/day, and the ratio of water and gas injection time – 90/30 days. The calculation period was 10 years.

Since a stochastic reservoir model was subsequently considered, permeability values varied from 10 to 60 md, with the average permeability for the object being 25.5 md. The initial oil saturation and porosity were determined for each layer, while the initial gas oil ratio (GOR) was set at143 m^3/m^3.

Given that the majority of Western Siberia's fields are currently in the 3rd stage of development (Mukhina et al. 2021; Dorhjie et al. 2023; Malozyomov et al. 2023), it is imperative to implement innovative techniques to boost oil recovery. One effective method is the incorporation of new methods that enhance the displacement of oil. The utilization of WAG (Water Alternating Gas) has proven to be highly effective in this regard, as it combines the advantageous qualities of both gas and water. To accurately assess the results, a supplementary evaluation of waterflooding was conducted when modelling the WAG process as a tertiary enhanced oil recovery (EOR).

A variety of choices were evaluated. Initially, the deposit functioned naturally for 1 – 2 years, allowing for the utilization of elastic forces and the inclusion of stagnant zones in development. Additionally, the duration of waterflooding implementation before water injection ranged from 1 to 5 years. Through the use of multivariate modelling, the following outcomes were achieved (Table 2).

Table 2. A tertiary enhanced oil recovery method using WAG for saturated and undersaturated reservoirs

No.	Options	Cumulative oil production, 1000 t	
		Undersaturated reservoir	Saturated reservoir
Implementation of water flooding (WF) from the first year of operation, along with the use of WAG			
1	WF from year one plus WAG from year two	60,583	29,983
2	WF from year one plus WAG from year three	60,65	30,900
3	WF from year one plus WAG from year four	60,196	32,073
4	WF from year one plus WAG from year five	55,654	29,418
Implementation of water flooding (WF) from the second year of operation, along with the use of WAG			
5	WF from year two plus WAG from year three	63,947	31,708
6	WF from year two plus WAG from year four	64,107	33,591
7	WF from year two plus WAG from year five	63,608	34,927

In the third and fourth years after waterflooding, the introduction of water alternating gas injection resulted in a marginal rise of 0.6 (0.19 thousand tons) and 4% (2.07 thousand tons) in the accumulated oil production for a gas-saturated reservoir that had undergone a period of depletion beforehand (see Fig. 1). Once the formation is operated in a natural mode, it is then subjected to waterflooding. This results in the restoration of reservoir pressure in the second year, causing a significant rise in fluid extraction. This can be attributed to the wider coverage of the formation due to development, as evidenced by a non-linear correlation in the accumulated oil production graphs (Osatemple et al. 2021; Al-Obaidi, Wang & Hofmann 2022).

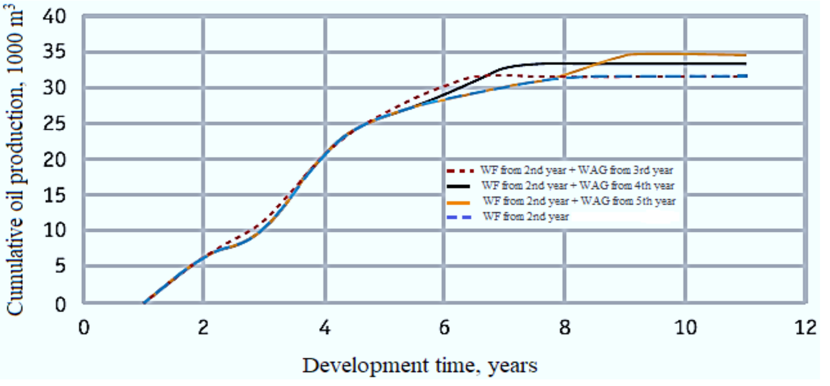

Figure 1. The utilization of WAG in a saturated reservoir results in a modification of the cumulative oil production

The reservoir system reaches its maximum capacity of dissolved gas, resulting in incomplete dissolution of any additional gas injected. This causes the removal of the fluid due to the increased gas-to-oil ratio (Fig. 2).

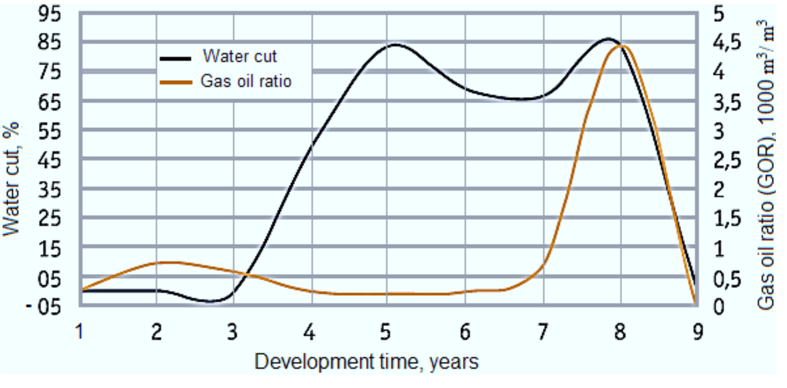

Figure 2. An analysis of the change in water cut and gas oil ratio for a gas-saturated reservoir

Simultaneously, implementation of WAG in the 5th year after waterflooding results in a significant 8% increase (equivalent to 3.41 1000 tons) in oil production compared to the traditional waterflooding method. The impact of utilizing WAG takes approximately 3 – 4 years to manifest.

Figure 3 illustrates how water-gas stimulation can serve as a tertiary technique for enhancing oil production in formations containing a low saturation pressure, which is a common feature of Upper Jurassic deposits.

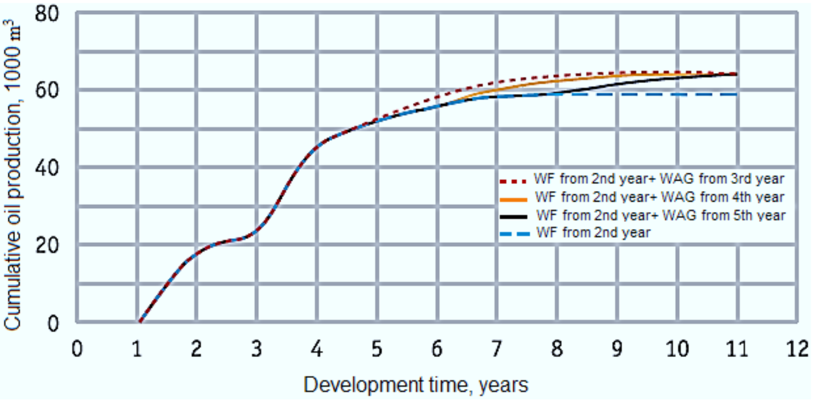

Figure 3. The utilization of WAG in an undersaturated reservoir results in a modification of the cumulative oil production

As the natural mode of reservoir operation increases, the total production of oil also increases (Jia et al. 2023; Liu et al. 2024). This increase is observed before the implementation of waterflooding. Additionally, on the graph, the shift from natural operation to the use of a reservoir pressure maintenance system can be seen as a bend with subsequent stabilization of the lines. This is due to a sharp withdrawal of oil when the development involves reservoir zones that have been affected by water flooding (Yongle et al. 2019; Tang et al. 2023). Based on the modelling results, it was noted that the best performance was achieved when using WAG in the second year after waterflooding; the maximum increase in fluid production in this case was 8.2% (4.8 thousand tons). With a further increase in the waterflooding time before WAG, the positive effect of WAG decreases. Thus, with water-gas impact on the formation in the 3rd year after waterflooding (from the 5th year of operation), the increase in accumulated production is already 7.3%.

The utilization of WAG technology after waterflooding enhances the displacement coefficient. This results in the involvement of poorly permeable sections of the reservoir in the development process, by replacing oil with gas in their pore spaces.

Additionally, the use of WAG technology facilitates a more uniform production of oil-saturated zones, as compared to the use of only waterflooding. This can be observed in the oil saturation cubes depicted in Figure 4.

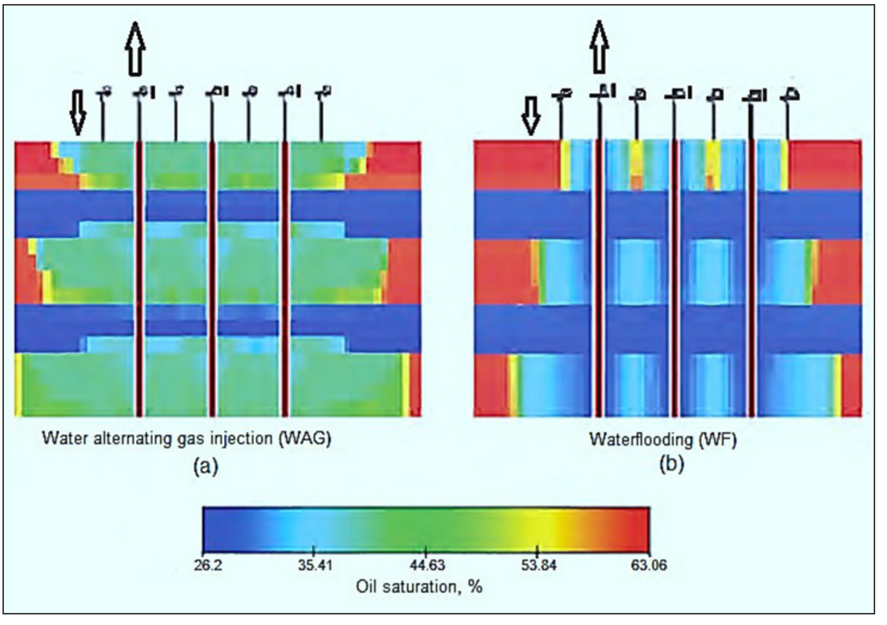

Figure 4. Comparison between waterflooding and WAG in terms of oil saturation distribution

This particular method, illustrated in Figure 4a, allows for a larger area of the reservoir to be covered. It achieves this by either penetrating the poorly permeable zones and substituting gas with oil in their pores, or dissolving the gas in the oil (particularly in viscous oil). The outcome of this application is an improved oil recovery process, resulting in higher recovery factors when utilizing WAG.

During the initial phase of reservoir development in its natural state, the pressure within the reservoir decreases to 16 MPa (as shown in Fig. 5). Later on, when waterflooding is implemented, the reservoir undergoes a recovery process. However, when gas is injected, there is a sudden spike in reservoir pressure due to the expansion of the gas-oil mixture. This highlights the significant impact of the pressure regime and the dissolved gas regime. Thus, the effectiveness of water-gas stimulation is significantly influenced by the initial state of the reservoir system.

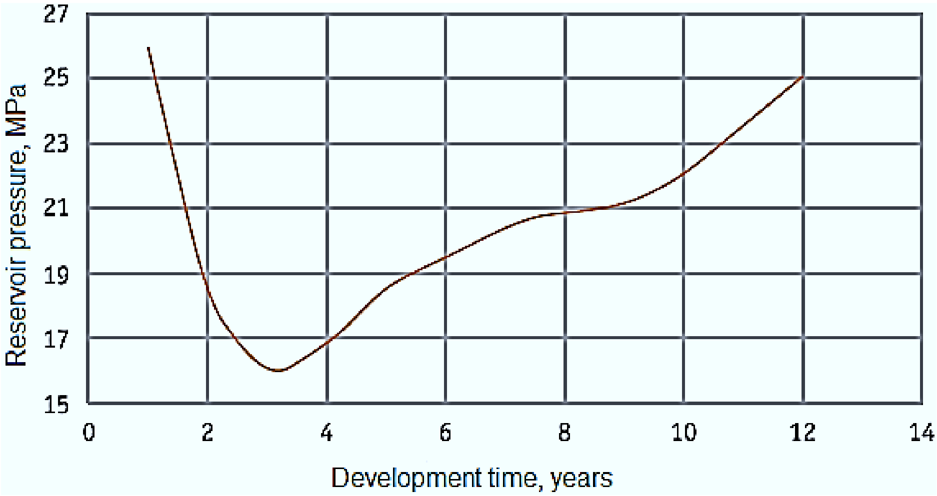

Figure 5. The change in reservoir pressure for an undersaturated reservoir

4. Conclusions

Water-gas stimulation may not be effective in gas-saturated reservoirs due to the rapid occurrence of gas breakthroughs. However, the effects of implementing WAG can be observed within 3-4 years and may lead to a 1-8% rise in overall oil production, contingent upon the timing of its implementation following waterflooding. The highest recorded increase of 8% was achieved by introducing WAG in the fifth year of development.

In general, cumulative production indicators with WAG are comparable to waterflooding. However, WAG may not be the best option due to the high development costs associated with the necessary technological equipment (Afzali, Rezaei & Zendehboudi 2018; Chang, Al-Obaidi & Patkin 2021).

At the same time, for reservoirs with low saturation pressure, which includes most Upper Jurassic formations, WAG is an effective method for increasing oil recovery. The WAG method is a highly effective technique that combines the advantageous properties of gas and water. While gas dissolves in the oil and increases the displacement coefficient, water boosts the sweep efficiency. As a result, the WAG method ensures a significant increase in the oil recovery coefficient compared to pure waterflooding. In this case, WAG injection can be used after waterflooding, but the waterflooding period should not be too long.

It is possible to increase oil recovery by up to 10% in Upper Jurassic reservoirs by using WAG (Water Alternating Gas) compared to conventional waterflooding. To maximize the potential of WAG as a tertiary method of enhancing oil recovery, it is recommended to operate the reservoir naturally for a long time, followed by waterflooding and the use of WAG in the second year after waterflooding. This approach has been proven to be highly effective in increasing oil recovery.

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✉ **Prof. Dr. Miel Hofmann**
ORCID iD: 0000-0001-5889-5351
Department of Petroleum Engineering
Mining University, Russia
E-mail: hof620929@gmail.com

✉ **Prof. Dr. Sudad H. Al-Obaidi**
ORCID iD: 0000-0003-0377-0855
Department of Petroleum Engineering
Mining University, Russia
E-mail: drsudad@gmail.com

✉ **Dr. Wang J. Chang, Assoc. Prof.**
ORCID iD: 0000-0002-5457-2923
Department of Petroleum Engineering
University of Xidian
Xi'an, Shaanxi 710126, China
E-mail: changwj962@gmail.com