

International Journal of Hydrogen Energy

Hydrogen geological storage in saline aquifers based on seasonal and hourly cyclic profiles and the effects of integrating cushion gas.

--Manuscript Draft--

Manuscript Number:	
Article Type:	Full Length Article
Section/Category:	Hydrides / Hydrogen Storage
Keywords:	Hydrogen storage, saline aquifers, hourly cyclic profile, reservoir performance, cushion gas, numerical simulation.
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Abstract:	Hydrogen storage in saline aquifers is a promising sustainable solution for addressing the intermittency of renewable energy sources while enabling large-scale energy decarbonization. This study evaluates the feasibility of hydrogen storage using numerical simulations based on seasonal and hourly cyclic profiles, with cyclic injection and withdrawal strategies over a 10-year period. A 3D synthetic reservoir model was developed to represent a typical saline aquifer, accounting for reservoir heterogeneity. The effects on the well and reservoir properties, such as gas rates and saturations, pressure and water production are discussed for both operational profiles, as well as the impacts of pre-injecting cushion gas. Hydrogen storage at the terawatt-hour (TWh) scale is achievable in both operational profiles, with the hourly one demonstrating greater efficiency and reduced water production compared to the seasonal profile. The injection of hydrogen cushion gas prior to the operational profiles improved initial withdrawal performance, though its benefits decreased over time.

Cover Letter

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February 10th 2025

Prof. Dr. T. Nejat Veziroglu

Founding Editor-in-Chief

International Journal of Hydrogen Energy

Miami, Florida, United States

Dear Prof. Dr. T. Nejat Veziroglu,

I am pleased to submit our manuscript titled "Hydrogen geological storage in saline aquifers based on seasonal and hourly cyclic profiles and the effects of integrating cushion gas" for consideration in the International Journal of Hydrogen Energy. This research presents a comprehensive numerical simulation study on the feasibility of large-scale hydrogen storage in saline aquifers, addressing both seasonal and hourly cyclic operational profiles, as well as the impact of cushion gas pre-injection on storage efficiency.

The transition to renewable energy sources is critical for achieving global decarbonization goals, yet the intermittent nature of renewables necessitates effective energy storage solutions. Our study explores the technical and operational challenges of underground hydrogen storage (UHS) in saline aquifers, leveraging advanced numerical simulations to evaluate reservoir performance, pressure management, and water production over a 10-year operational period.

Relevant findings of our research include the demonstration that terawatt-hour (TWh) scale hydrogen storage is achievable in heterogeneous saline aquifers, with hourly cyclic profiles showing greater withdrawal efficiency and reduced water production compared to seasonal profiles. Additionally, the pre-injection of cushion gas enhances initial withdrawal performance, though its benefits diminish significantly over the operational period, suggesting a nearly negligible impact on the long-term storage of hydrogen in porous media.

We believe that this manuscript aligns well with the scope of the International Journal of Hydrogen Energy, as it addresses critical issues related to hydrogen storage, renewable energy integration, and sustainable energy systems. We hope the findings presented in this paper have the potential to contribute to both academic research and future industrial large-scale storage projects in the field of hydrogen energy.

This manuscript is original, has not been published elsewhere, and is not under consideration for publication in any other journal. All authors have approved the manuscript and its submission to your journal. We have no conflicts of interest to disclose.

Thank you for considering our submission. We look forward to the possibility of contributing to the International Journal of Hydrogen Energy. Please do not hesitate to contact me if you require any additional information or materials.

Sincerely,

Dr. Pedro Miguel Martins Pereira

Center for Sci-Tech Research in Earth System and Energy (CREATE), University of Évora

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Highlights

- Terawatt-hour (TWh) scale hydrogen storage is achievable in heterogeneous saline aquifers using both seasonal and hourly cyclic operational profiles, with hourly profiles demonstrating greater efficiency and reduced water production.
- Hourly cyclic profiles outperform seasonal profiles in terms of reservoir pressure management, hydrogen recovery, and minimizing water production over a 10-year operational period.
- Pre-injection of cushion gas improves initial withdrawal performance, but its benefits diminish over time, indicating limited long-term impact on hydrogen storage efficiency.
- Water production remains a key challenge in underground hydrogen storage, but it can be significantly reduced by adopting hourly cyclic profiles and optimizing operational strategies.

Hydrogen geological storage in saline aquifers based on seasonal and hourly cyclic profiles and the effects of integrating cushion gas

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Abstract

Hydrogen storage in saline aquifers is a promising sustainable solution for addressing the intermittency of renewable energy sources while enabling large-scale energy decarbonization. This study evaluates the feasibility of hydrogen storage using numerical simulations based on seasonal and hourly cyclic profiles, with cyclic injection and withdrawal strategies over a 10-year period. A 3D synthetic reservoir model was developed to represent a typical saline aquifer, accounting for reservoir heterogeneity. The effects on the well and reservoir properties, such as gas rates and saturations, pressure and water production are discussed for both operational profiles, as well as the impacts of pre-injecting cushion gas. Hydrogen storage at the terawatt-hour (TWh) scale is achievable in both operational profiles, with the hourly one demonstrating greater efficiency and reduced water production compared to the seasonal profile. The injection of hydrogen cushion gas prior to the operational profiles improved initial withdrawal performance, though its benefits decreased over time.

Keywords: Hydrogen storage, saline aquifers, hourly cyclic profile, reservoir performance, cushion gas, numerical simulation.

1. Introduction

The transition to sustainable energy sources is essential for addressing the challenges posed by significant increase of greenhouse gas emissions, exacerbating climate change. Hydrogen gas is increasingly recognized as a clean energy and its versatility is acknowledged as a solution for decarbonizing sectors such as transportation, power generation, heating, and heavy industries, contributing to the reduction of large-scale greenhouse gas emissions [[1], [2]]. Renewable energy sources such as solar, wind, biomass, and geothermal are also considered key alternatives to reduce the dependency on fossil fuels [[3], [4]]. However, their intermittent nature results in fluctuations in electricity production, often leading to a mismatch between energy supply and demand caused by diurnal cycles, weather conditions, and seasonal changes [[5], [6]]. Excess electricity during peak production can be stored for later use by converting it into hydrogen through water electrolysis [7]. Still, the widespread adoption of hydrogen relies on the development of effective and safe large-scale storage solutions [5].

The surface-based storage facilities, including tanks and pipelines, are the most common methods currently used for hydrogen storage. While these options offer convenience and

accessibility, they have notable limitations, including the insufficient storage capacity for large-scale energy applications and the safety risks due to potential leaks, which can lead to significant hydrogen loss and atmospheric contamination [5]. In contrast, underground hydrogen storage (UHS) in geological formations is emerging as a viable alternative for large-scale, cost-effective, and environmentally friendly medium- to long-term storage, providing large subsurface storage space and enhancing storage safety due to the less influence by environmental factors [8]. Hydrogen can be stored in distinct formations, including salt caverns, rock caverns, depleted hydrocarbon reservoirs, and saline aquifers [9], offering a range of storage and delivery capacities for both seasonal and daily energy needs. Salt caverns provide flexible, short-term delivery and reliable cyclic operations with a lower risk of hydrogen contamination [5]. However, their limited geographic availability and storage capacity restrict their suitability for large-scale decarbonization [5]. Conversely, depleted gas fields and saline aquifers can potentially store hundreds of terawatt-hours (TWh) of hydrogen, making them suitable for seasonal energy storage [5]. Saline aquifers, distributed globally [10], offer a significantly large storage capacity [[11], [12]], often representing the only viable geological option for hydrogen storage near renewable energy generation sites [12]. Compared to the salt caverns, they are also considered a more environmentally sustainable subsurface storage option, as their deployment does not require freshwater injection, unlike the leaching process for constructing salt caverns [11]. In addition, the risk of hydrogen contamination during aquifer storage operations is minimal, comparing to depleted hydrocarbon fields, further enhancing their appeal due to low microbial activity in high-salinity environments [13].

Hydrogen storage in saline aquifers is technically and operationally comparable to natural gas storage and carbon capture and storage (CCS). Extensive research and field experience with CCS and natural gas storage in aquifers provide valuable insights into the feasibility of underground hydrogen storage [14]. Nevertheless, each underground storage site has unique characteristics, but certain principles apply universally [15], including the reservoir performance and containment and the reservoir engineering insights [16]. Detailed geological assessments and numerical simulations are essential for accurately evaluating the potential of these formations [11], which involve simulating storage operations under various conditions, and optimizing cyclic injection and withdrawal strategies, well configuration planning, and efficient pressure management to ensure the long-term integrity of the subsurface storage complex. UHS projects typically follow seasonal energy cycles, with injection during periods of excess supply and withdrawal during high-demand periods, such as winter [[13], [17], [18]].

This paper addresses numerical dynamic simulation studies, under the scope of the H2GeoStore project, to evaluate the impacts on the injection and withdrawal phases based on seasonal and hourly operational cyclic profiles for hydrogen storage in a heterogeneous saline aquifer. In addition, the pre-injection of cushion gas is considered, and the outcomes are presented and discussed in the final part of this work.

2. Material and Methods

2.1. Operational Cyclic Profiles

Operational cyclic profiles define the injection and withdrawal strategies used to manage the reservoir over the lifespan of hydrogen storage. Two distinct operational profiles, designated in this work as seasonal and hourly cyclic profiles (Fig. 1), aim to account for the variations of the surplus of energy generation and energy demand in the injection and withdrawal phases, respectively. These profiles were designed to represent typical seasonal and hourly intermittency scenarios of the energy generation from the renewable energy sources, in this case, of wind power over a one-year period. The base data used are the wind power generation in Portugal for an installed capacity of 5.37 GW and the consumption of natural gas in all sectors of activity. For the numerical purposes of this work, the operational lifespan of 1-year in both defined profiles were extended to a 10-years period, therefore accounting for 10-cycles, to address the impacts of the operations over time.

2.1.1. Seasonal Cyclic Profile

The seasonal cyclic profile (Fig. 1) was established based on a case scenario derived from renewable energy sources, particularly from wind energy. During the autumn and winter seasons, wind power generation is anticipated to be higher, leading to a surplus of energy, which is available to be stored. Part of this stored energy will then be recovered and consumed during the summer season when wind power is expected to be lower, thereby bridging the energy gap.

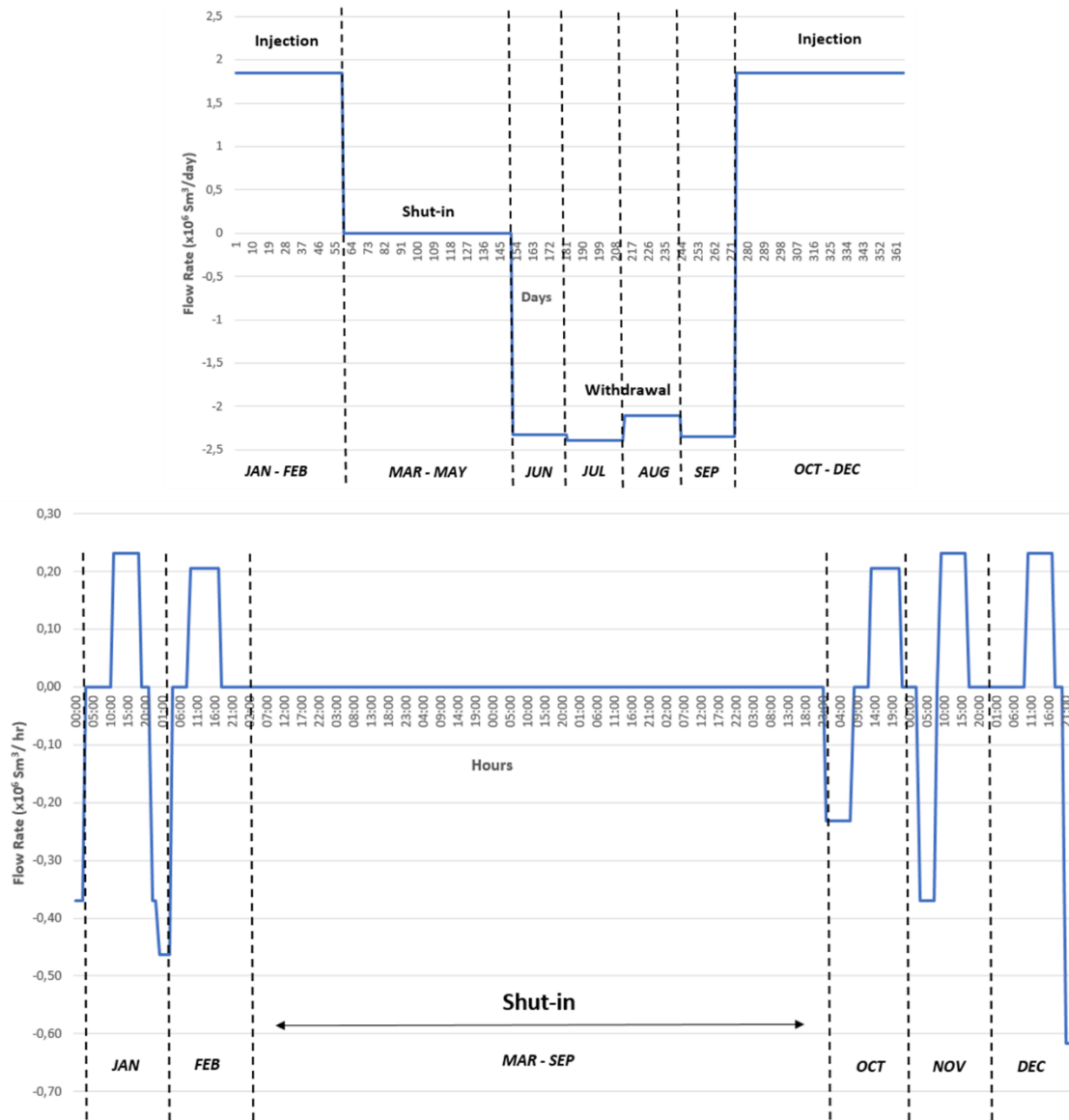


Fig. 1. Seasonal (top) and hourly (bottom) operational profiles of 1-cycle illustrating the injection, withdrawal and shut-in periods (daily and hourly values, respectively). The positive flow rates correspond to the injection phases and the negative flow rate values to the withdrawal phases.

In detail, the seasonal cyclic profile is composed of an injection period of five months, from October to February (151 days), by imposing daily constant flow rates of $1.85 \times 10^6 \text{ Sm}^3/\text{day}$; a shut-in period of three months, from March to May (92 days), during which no gas is injected or withdrawn; and finally a withdrawal period of four months, from June to September (122 days), with the flow rate of $2.32 \times 10^6 \text{ Sm}^3/\text{day}$, $2.39 \times 10^6 \text{ Sm}^3/\text{day}$, $2.10 \times 10^6 \text{ Sm}^3/\text{day}$ and $2.35 \times 10^6 \text{ Sm}^3/\text{day}$, respectively for each month. The daily production of each month in the withdrawal phase varies slightly depending on the operation conditions of the field and the energy demand.

2.1.2. Hourly Cyclic Profile

Contrarily to the seasonal profile, the hourly cyclic profile was only defined between October-February, presenting a continuous shut-in period of seven months (March-September). Over the five months of operations during a typical year, five injection phases and five withdrawal phases occur with several hourly shut-in periods in between these phases. Comparing to the seasonal

profile, the daily flow rates of the injection phases are the same in this hourly profile, which are approximately 1.85×10^6 Sm³/day. However, these flow rates vary hourly depending on the number of hours defined per day for each month of this operational profile, as illustrated in Fig. 1, corresponding to 0.23×10^6 Sm³/hr over the five months of the injection phase. Likewise, the flow rates of the withdrawal phases also vary hourly, setting daily constant flow rates over the days of a given operational month, ranging between 0.21×10^6 Sm³/hr (February and October) and 0.23×10^6 Sm³/hr (January, November and December) in the injection phases, while in the withdrawal phases, the flow rates vary between 0.23×10^6 Sm³/hr (October) and 0.62×10^6 Sm³/hr (December). It is important to note that, despite the months of the withdrawal phases are five and four, for the hourly and seasonal cyclic profiles, respectively, identical overall withdrawal flow rates were considered in the design of both profiles.

The evaluation of the pre-injection of cushion gas was also considered at the end of this work for both operational profiles based on the same assumptions: the pre-injected cushion gas type is hydrogen, and a constant flow rate of 1.85×10^6 Sm³/day was defined over a period of nine months (from January until October), before starting the generated profiles as shown in Fig. 1.

2.2. Modelling Domain

2.2.1. Reservoir Simulation Model

A 3D synthetic model was built under the scope of H2GeoStore project using the geostatistical modelling methods from Aspen SKUA software to mimic a typical anticline geological structure for hydrogen storage. This reservoir model aims to realistically represent a saline aquifer from Lower Cretaceous composed of siliciclastic deposits, primarily sands, with interbedded clay layers [19]. The model built presents a 4-way dip closure and exhibits vertical and lateral variability, consisting of in both structural and stratigraphic trapping mechanisms. At the top of the reservoir, the presence of an impermeable layer acting as a caprock was assumed in this study, but not incorporated in the simulation.

In addition, and due to the lateral extension of the reservoir model, the dynamic simulations were conducted using model closed boundaries. The average thickness of the reservoir is approximately 300 m, and the median values of the petrophysical properties are 19% for porosity, and 35 mD and 5 mD for the horizontal and vertical permeability, respectively, as illustrated in Fig. 2. The probability distribution functions of the reservoir petrophysical properties were derived after previous works [[20], [21]]. The reservoir simulation model was discretized in 100 x 91 x 160 uniform blocks with the dimensions of 100x100 m in the horizontal and 2 m in vertical.

2.2.2. Well Parameters and Constraints

The flow rates of the operational cyclic profiles were implemented in a set of six wells with dual-purpose with conversion configuration i.e., the injection and withdrawal phases of both operational profiles are conducted for each well at the same model location (Fig. 2). The flow rates per well for the seasonal and hourly cyclic profiles are listed in Table 1 and Table 2, respectively, corresponding to the well constraints for the maximum gas rate in the operational profiles.

For the bottom-hole pressure (BHP), a value of 12000 kPa was set as the maximum BHP for the injection phases, while a value of 5000 kPa was set as the minimum BHP for the withdrawal phases. In addition, a constant value of 100 m was defined for the perforation intervals across the set of wells, distributed in the reservoir model using a lateral distance of approximately 1 km between them.

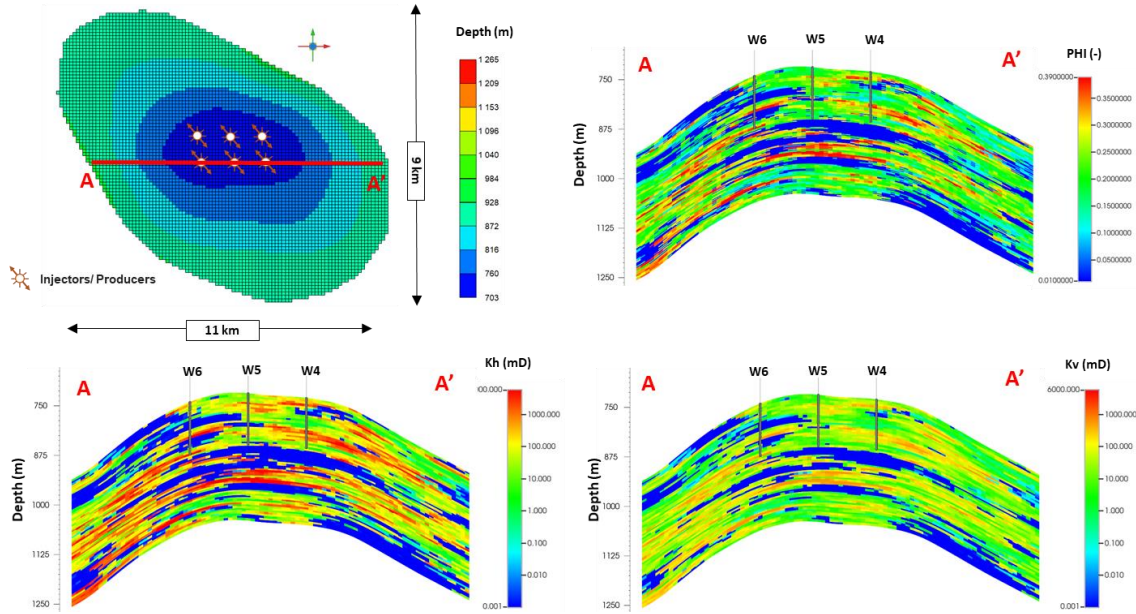


Fig. 2. Top view of the reservoir model with injector/producer wells, and cross-sections of petrophysical properties: porosity (PHI), horizontal permeability (Kh), and vertical permeability (Kv).

Table 1. Flow rates per well for the injection and withdrawal (production) phases of the seasonal profile.

Injection/ Withdrawal Phases	Flow Rates (Sm ³ /day)
Injection/well	308 333
Production/well (June)	386 667
Production/well (July)	398 333
Production/well (August)	350 000
Production/well (September)	391 667

2.2.3. Reservoir Parameters

The numerical simulations of this work were carried out using the software package developed by the Computer Modelling Group (CMG). Initially, the CMG-WinProp™ phase behavior simulator was employed to determine the properties of the gas component (hydrogen) under the reservoir model conditions (i.e., initial pressure and temperature). The fluid flow simulations were carried out using the CMG-GEM™ numerical simulator and the Peng-Robinson equation of state. The governing equations and nonlinear thermodynamic relations explaining the instantaneous phase equilibrium of heterogeneous fluids are coupled in this compositional simulator are described in [17]. The rock and fluid properties of the reservoir are listed in Table 3. The reference depth of the model was set to 900 m with a reference pressure and temperature of 10 MPa and 40 °C, respectively.

Table 2. Flow rates per well for the injection and withdrawal phases of the hourly profile.

Months	Injection/ Withdrawal Phases	Flow Rates (Sm ³ /hr)	Number of hours/ day
January	Injection/well	38 550	8
	Production/well	61 667	5
February	Injection/well	34 267	9
	Production/well	77 083	4
October	Injection/well	34 267	9
	Production/well	38 550	8
November	Injection/well	38 550	8
	Production/well	61 667	5
December	Injection/well	38 550	8
	Production/well	102 783	3

Table 3. Rock and fluid properties of the reservoir.

Parameters		Values	Units
Rock Properties	Porosity	0.001 – 0.39	-
	Horizontal Permeability	0.001 – 6667	mD
	Vertical Permeability	0.001 – 667	mD
	Temperature	38 – 42	°C
	Pressure	7 – 13	MPa
	Rock Compressibility	4.5E ⁻⁷	kPa ⁻¹
	Rock Density	2300	kg/m ³
	Water Saturation	0.9	-
	Reference Depth	900	m
	Reference Temperature	40	°C
	Reference Pressure	10	MPa
Brine Properties	Density	1062	kg/m ³
	Compressibility	4.1E ⁻⁷	kPa ⁻¹
	Viscosity	0.8	cp
	Salinity	100	g/L
	Reference Pressure	10	MPa

3. Results and Discussion

3.1. Hydrogen Gas Rates of Injection and Withdrawal Phases

The numerical simulations based on the seasonal cyclic profile successfully achieved the established maximum injection flow rate of 308 333 Sm³/day per well over the defined 10-year lifetime, except for injection wells 2 and 5 during the first cycle (Fig. 3). However, during the withdrawal phase of the 1st cycle, no producer wells were able to retrieve the designated hydrogen volumes according to the seasonal cyclic profile after the first month of withdrawal (i.e., June 2025). Despite this, hydrogen production gradually increased in subsequent withdrawal phases. By 2032, producer wells 3 and 4 were able to consistently produce the maximum defined flow rates during the four-month production phase. Between 2034 and 2035, corresponding to the 10th cycle, well 5 successfully produced the total hydrogen volumes, except for September 2034. The remaining three wells struggled to meet the established hydrogen

volumes throughout the storage lifetime, including during the final cycle (Fig. 3). This was primarily due to BHP constraints and reservoir heterogeneities in the vicinity of these wells, which will be further discussed in the following subsections.

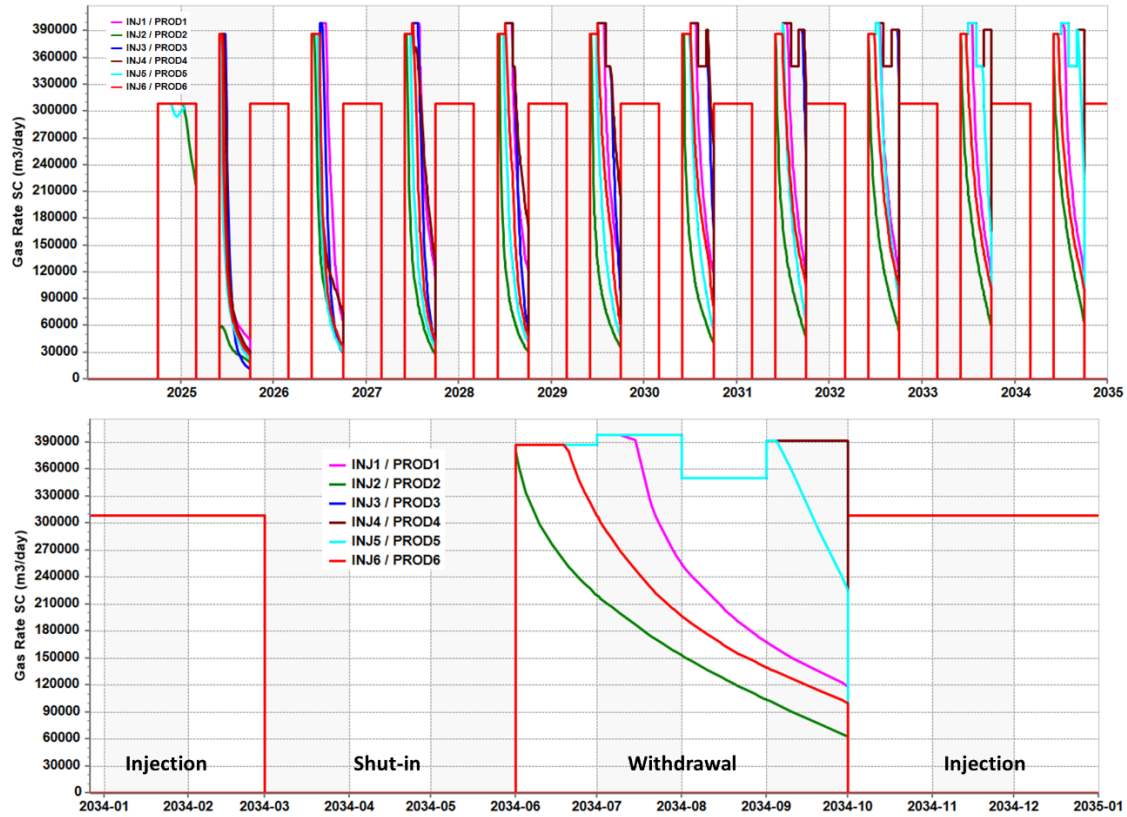


Fig. 3. Hydrogen gas rate per day of the set of six wells in the injection and withdrawal phases for the seasonal cyclic profile over 10 years (top) and a zoom-in of the 2034-2035 period (bottom).

Similar results were observed in the injection and withdrawal phases when considering the hourly cyclic profile. The established hourly injection flow rates of 34 267 Sm³/hr (October and February) and 38 550 Sm³/hr (November, December, and January) were achieved for all wells over the 10 cycles, with the exceptions of injection wells 2 (during the 1st cycle) and 5 (during the 1st cycle and October of the 2nd cycle).

Producer wells also faced difficulties in meeting the defined hydrogen volumes during the cycles, with producer well 4 being the only one to fully produce hydrogen at the specified hourly flow rates after 2029 (i.e., the 5th cycle), as shown in Fig. 4. This included the challenging switch in December to an hourly flow rate of 102 783 Sm³/hr, which was nearly double the flow rate in November and January (i.e., 61 667 Sm³/hr).

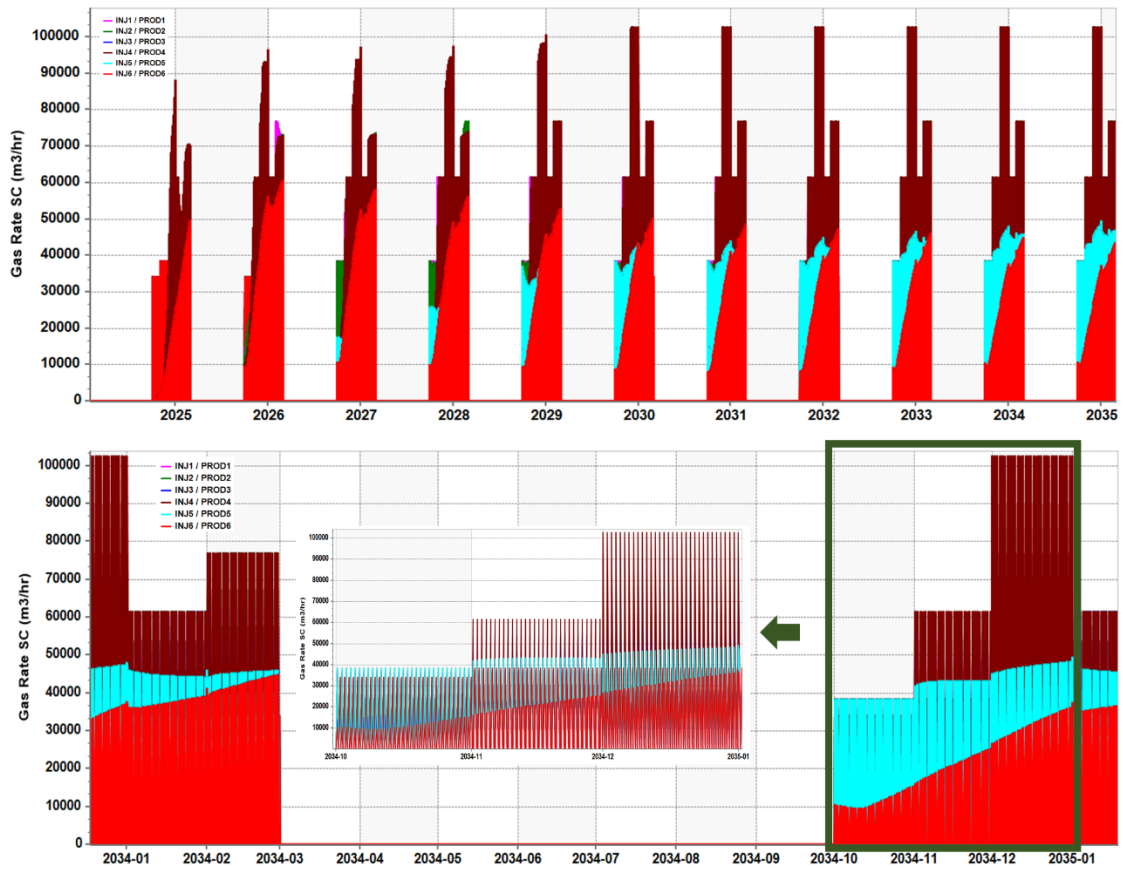


Fig. 4. Hydrogen gas rate per hour of the set of six wells in the injection and withdrawal phases for the hourly cyclic profile over 10 years (top) and a zoom-in of the 2034-2035 period (bottom).

3.2. Bottom-hole Pressure of Injection and Withdrawal Phases

The performance of hydrogen flow rates is strongly influenced by BHP variations over time during both the injection and withdrawal phases. These variations are primarily due to existing reservoir heterogeneities at the locations of the operational wells (Fig. 2). Following the initial reservoir pressure equilibrium, BHP build-ups were observed during the injection phases, particularly in the 1st cycle for both cyclic profiles (Fig. 5 and Fig. 6). This led to rapid achievement of the maximum BHP constraint of 12000 kPa, which in turn halted hydrogen injection into the reservoir.

Conversely, the minimum BHP constraint of 5000 kPa limited the ability of most producer wells to retrieve the established hydrogen flow rates over the 10-year operational period. Additionally, BHP in both seasonal and hourly cyclic profiles gradually decreased over time during both the injection and withdrawal phases. However, the reduction in BHP was more pronounced in the seasonal cyclic profile, as longer injection and production periods led to more significant pressure drops. In contrast, the hourly cyclic profile, with its more frequent flow rate adjustments and lower flow rates, resulted in less pressure depletion, contributing to better reservoir pressure management over time.

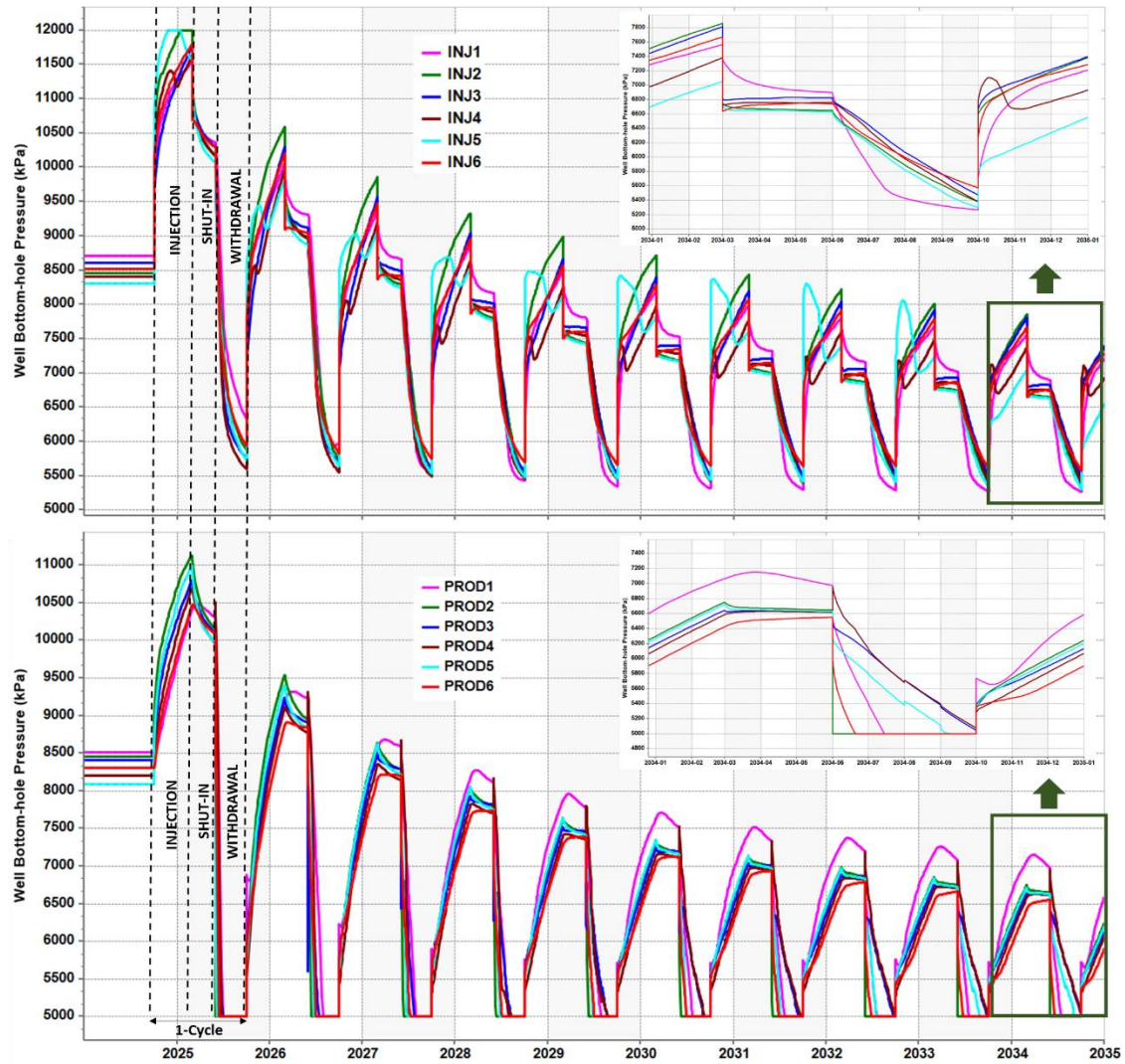


Fig. 5. Bottom-hole pressure of the set of six injector (top) and producer (bottom) wells for the seasonal cyclic profile over 10 years.

3.3. Reservoir Gas Saturation and Pressure Evolution

The numerical simulations conducted on the complex and highly heterogeneous aquifer model (Fig. 2) also provided insights into the spatial impact of varying petrophysical properties and the resulting velocity variations in different aquifer zones during hydrogen injection and withdrawal phases. Continuous hydrogen injection over extended periods, such as in the seasonal storage scenario, led to the spatial dispersion of hydrogen plumes away from the injection wells. This may result in higher hydrogen losses over time or create inter-well accumulations that could potentially not be recovered by producer wells. These losses could be exacerbated by residual gas saturation effects caused by reservoir heterogeneity (Fig. 7).

Although shortening the storage cycle time by increasing the injection and withdrawal cycles, as in the hourly cyclic profile, does not entirely resolve the intrinsic challenges of porous media (particularly saline aquifers), it can significantly reduce the extent of hydrogen saturation plumes from cycle to cycle. This improvement is evident in Fig. 7 when comparing the hydrogen plume extension and saturation rate after the withdrawal phases of the 5th and 10th cycles with the seasonal reservoir sections. Furthermore, as previously noted from the 1D-scale BHP data, the hourly cyclic profile results show more stable spatial variations in reservoir pressure, both

laterally and vertically. Pressure drops in the vicinity of operational wells are significantly reduced, as illustrated in Fig. 8.

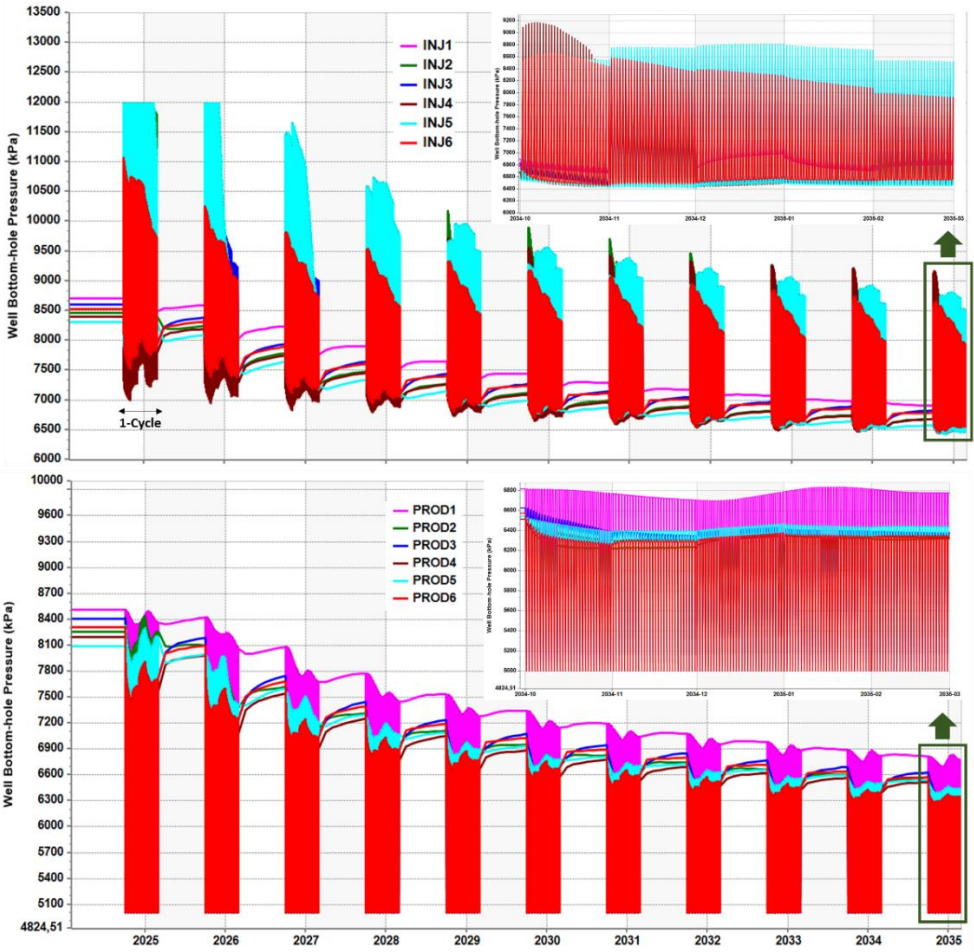


Fig. 6. Bottom-hole pressure of the set of six injector (top) and producer (bottom) wells for the hourly cyclic profile over 10 years.

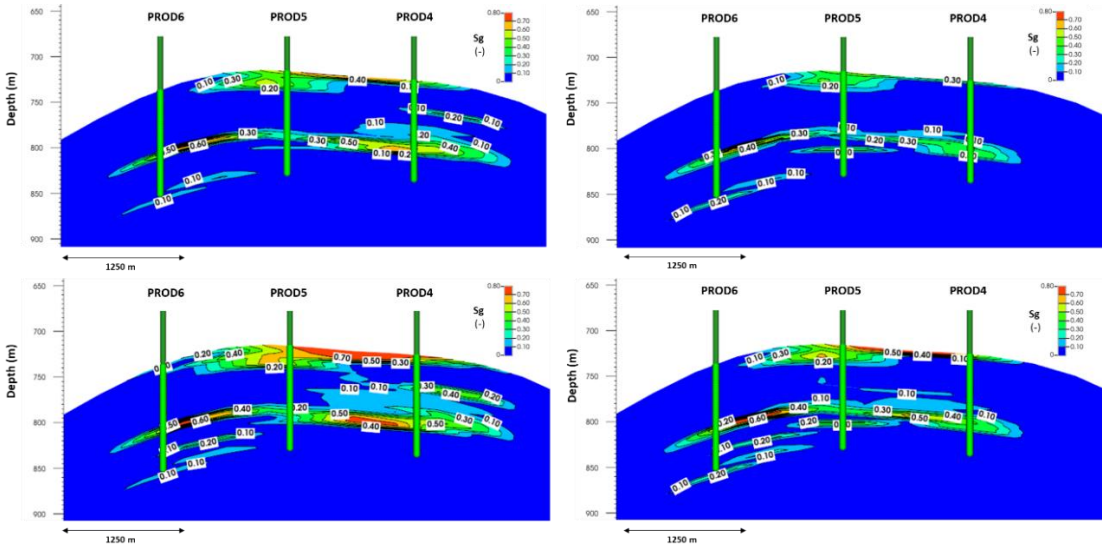


Fig. 7. Reservoir gas saturation evolution after the withdrawal phases in (top) October 2029 (5th cycle) and (bottom) October 2034 (10th cycle) for the seasonal cyclic profile (left) and hourly cyclic profile (right). The location of the cross-section is illustrated by the red line in Fig. 2.

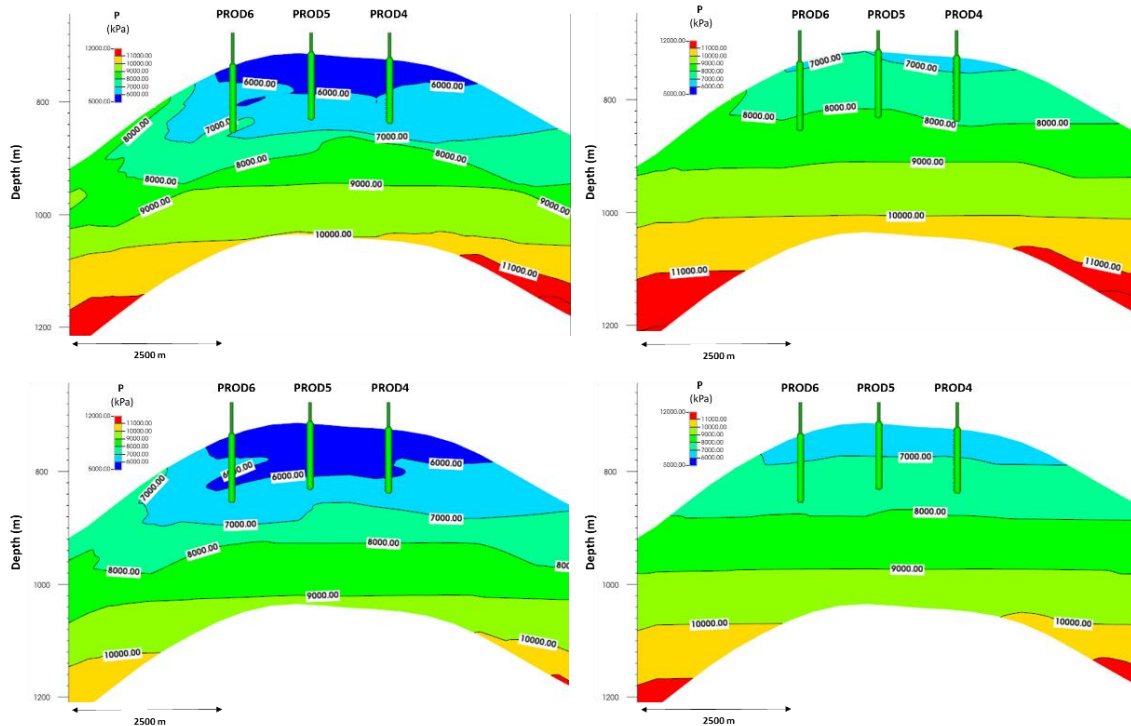


Fig. 8. Reservoir pressure evolution after the withdrawal phases in (top) October 2029 (5th cycle) and (bottom) October 2034 (10th cycle) for the seasonal cyclic profile (left) and hourly cyclic profile (right). The location of the cross-section is illustrated by the red line in Fig. 2.

3.4. Water Production During Withdrawal Phases

Water production progressively decreases in both operational storage profiles over the 10-year storage lifetime. However, the hourly profile exhibits lower and more stable water production compared to the seasonal cyclic profile. Among the wells, initial peaks in daily water production, particularly in Well 3 during withdrawal phases (Fig. 9), are attributed to a highly permeable reservoir layer near the perforation interval. This condition results in a greater pressure differential and propagation, enhancing the water coning effect, which is more pronounced in the seasonal profile due to higher operational flow rates.

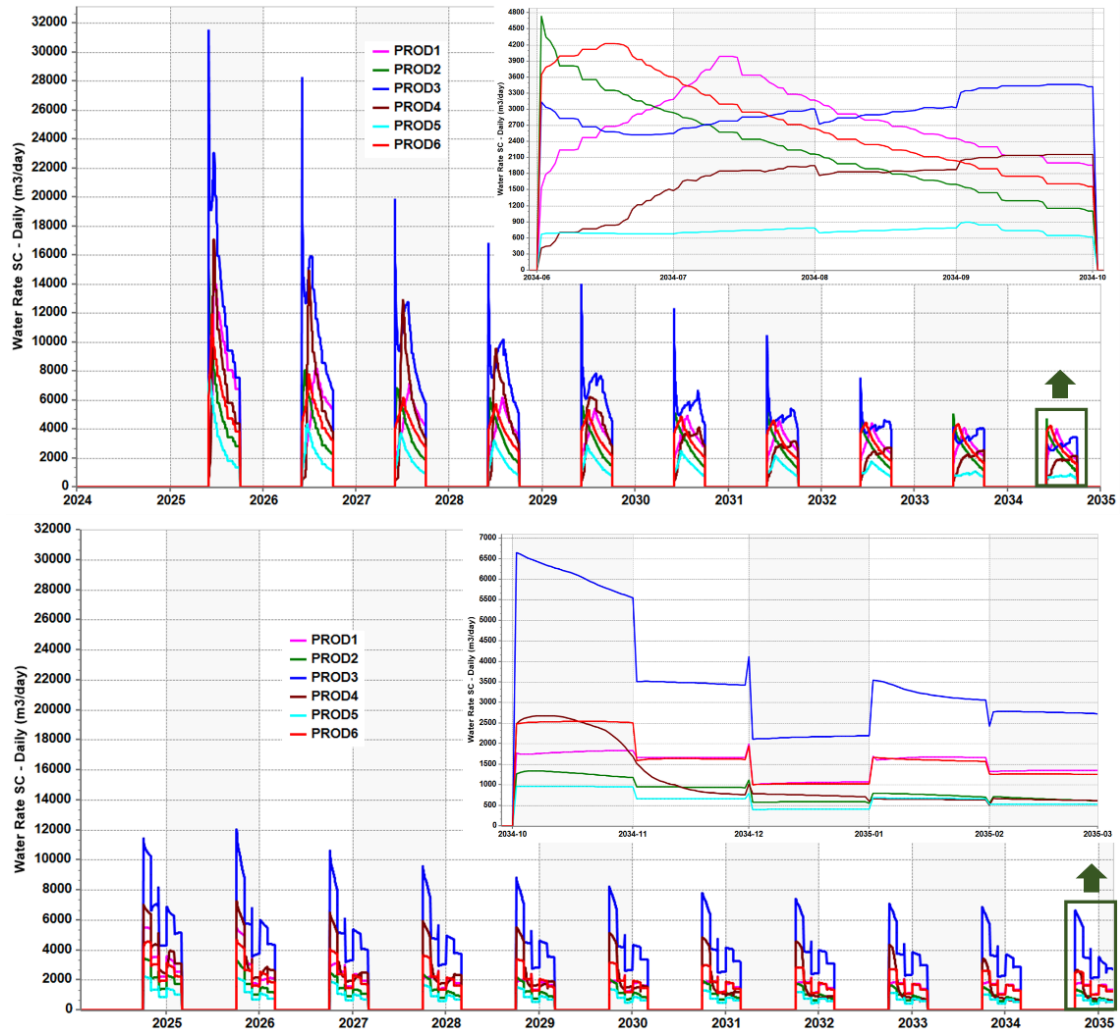


Fig. 9. Daily production rate of water of the set of six producer wells in the withdrawal phases for the seasonal (top) and hourly (bottom) cyclic profiles over 10 years.

3.5. Effects of Pre-Injection of Cushion Gas

Pre-injecting cushion gas (hydrogen) for nine consecutive months significantly enhances gas production during the withdrawal phases of the 1st cycle for both operational profiles (Fig. 10). However, the difference in gas rates between scenarios with and without pre-injection diminishes over time after the 1st cycle. Most wells, except for Injector Well 5, could not inject the full volume of cushion gas due to reaching the maximum BHP constraint of 12000 kPa. Gas injection rates started declining at various points in 2024, depending on local reservoir properties, with all wells experiencing simultaneous declines around April-May 2024 (Fig. 10).

Cumulative gas production over the 10-cycle storage lifetime shows that pre-injection of cushion gas results in higher hydrogen withdrawal volumes for both profiles (Fig. 11). The hourly profile demonstrates the highest cumulative production and faster growth rates per cycle compared to the seasonal profile. Notably, the seasonal profile with pre-injection achieves similar hydrogen withdrawal volumes as the hourly profile without pre-injection. Withdrawal efficiency increases by approximately 7% and 10% in the seasonal and hourly profiles, respectively, when pre-injection is applied, with the hourly profile reaching an efficiency of up to 74% by the 10th cycle.

All scenarios achieve TWh-scale energy production, with the hourly profile with pre-injection recovering more than 7.6 TWh of stored energy.

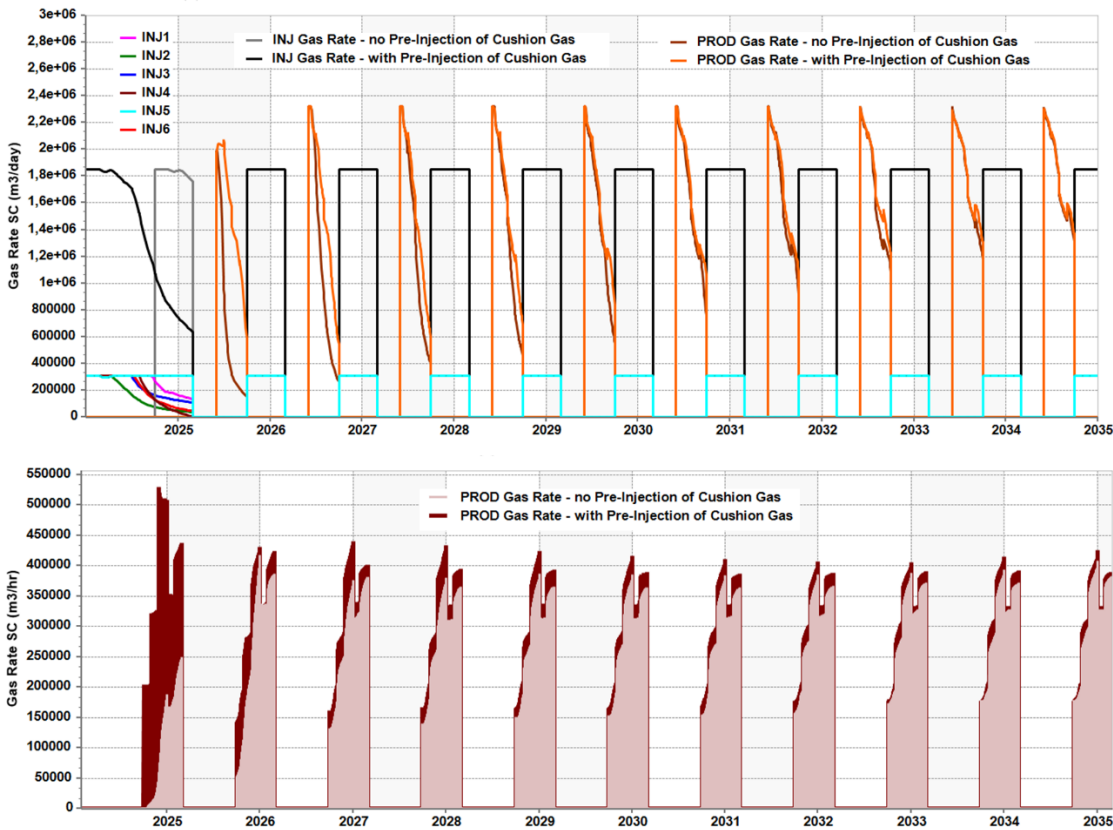


Fig. 10. Hydrogen gas rate for all the wells simultaneously in the injection and withdrawal phases of the seasonal cyclic profile (top), and in the withdrawal phases of the hourly (bottom) cyclic profile, integrating the pre-injection of cushion gas (hydrogen) over 10 years. The gas rate per well during the pre-injection period is also illustrated for the seasonal cyclic profile (top).

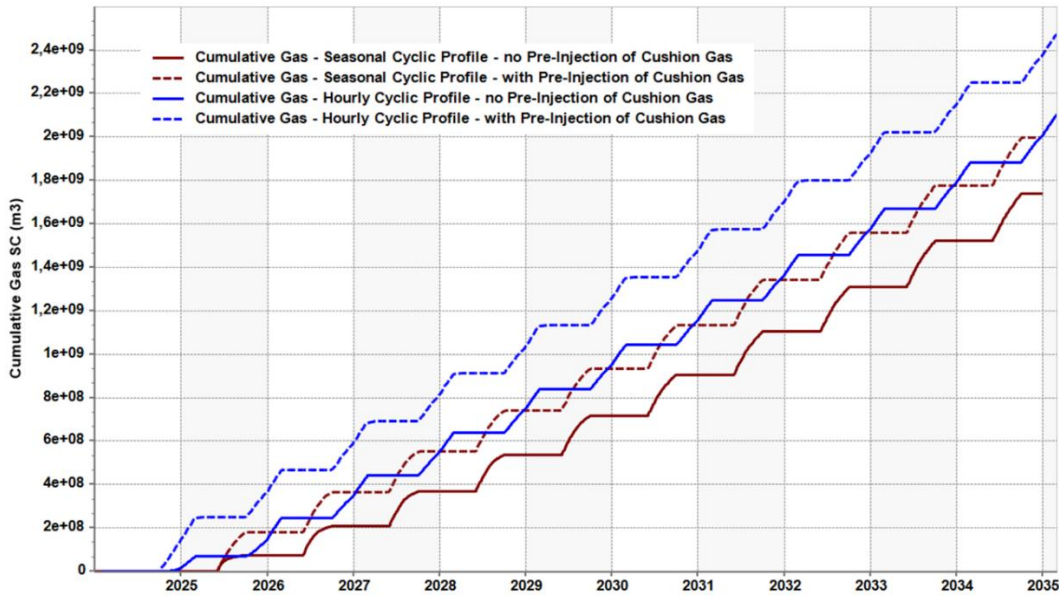


Fig. 11. Cumulative gas production integrating the pre-injection of cushion gas in both operational cyclic profiles over 10 years.

Table 4. Summary of the cumulative volumes of hydrogen, operational storage efficiency and energy stored and produced for the injection and withdrawal phases after the 1st, 5th and 10th cycles.

Cycles/ Operational Profiles		Pre-Injection of Cushion			Pre-Injection of Cushion		
		Injection Phases	Withdrawal Phases		Injection Phases	Withdrawal Phases	
			Seasonal Profile	Hourly Profile		Seasonal Profile	Hourly Profile
1 st cycle	Volumes (m ³)	2.8x10 ⁸	7.5x10 ⁷	6.9x10 ⁷	7.1x10 ⁸	1.8x10 ⁸	2.5x10 ⁸
	Efficiency (%)	-	26.79	24.64	-	25.35	35.21
	Energy (TWh)	0.931	0.250	0.230	2.631	0.599	0.832
5 th cycle	Volumes (m ³)	1.4x10 ⁹	7.2x10 ⁸	8.4x10 ⁸	1.7x10 ⁹	9.8x10 ⁸	1.1x10 ⁹
	Efficiency (%)	-	51.43	60.00	-	57.65	64.71
	Energy (TWh)	4.662	2.398	2.797	6.327	3.263	3.663
10 th cycle	Volumes (m ³)	2.8x10 ⁹	1.7x10 ⁹	1.9x10 ⁹	3.1x10 ⁹	2.0x10 ⁹	2.3x10 ⁹
	Efficiency (%)	-	60.71	67.86	-	64.52	74.19
	Energy (TWh)	9.324	5.661	6.327	10.989	6.660	7.659

Water production remains a key challenge for underground hydrogen storage in porous media, particularly in saline aquifers. Although pre-injecting cushion gas reduces cumulative water production (Fig. 12), its impact on the overall process is limited and depends on cost-effectiveness. Optimization of gas flow rates and pre-injection durations is critical for maximizing efficiency of withdrawal phases.

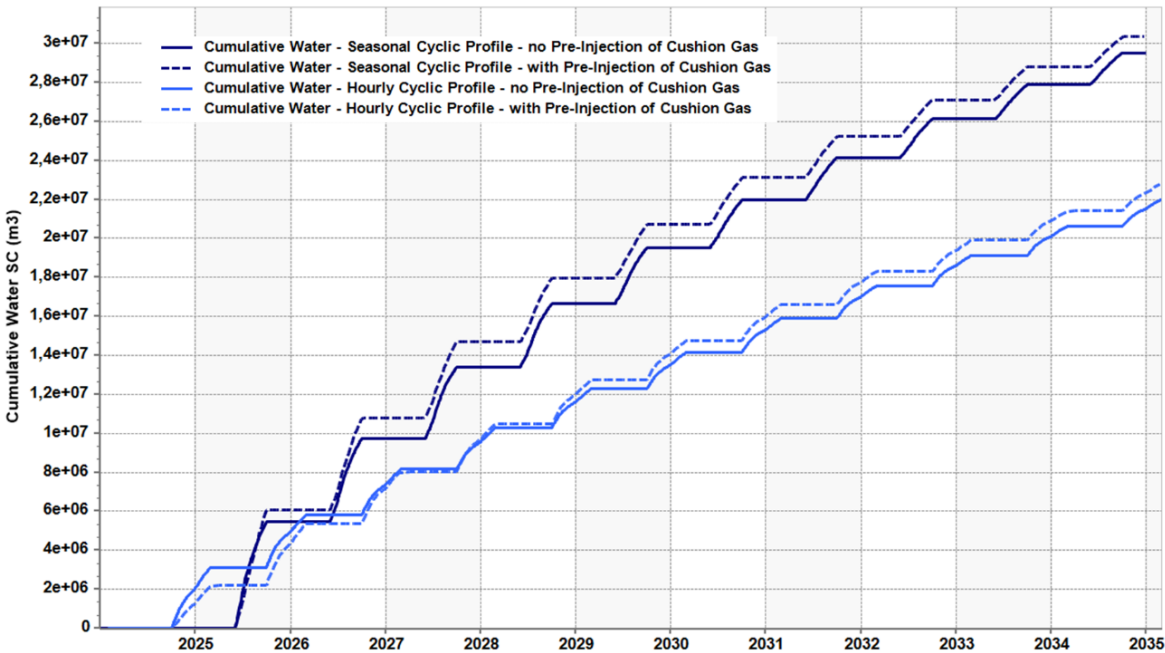


Fig. 12. Cumulative water production integrating the pre-injection of cushion gas in both operational cyclic profiles over 10 years.

Faster cycling between injection and withdrawal phases, as seen in the hourly profile, significantly reduces water production and may be more impactful than pre-injection alone. Depending on economic feasibility, produced water could be re-injected into the reservoir in nearby zones adjacent to the operational areas. This re-injection could involve direct water injection or pre-dissolving CO₂ in the produced water. Such an approach offers multiple benefits: managing excess water production, reducing CO₂ emissions through storage, and maintaining reservoir pressure for long-term operations.

4. Conclusions

Hydrogen energy storage in porous media, particularly saline aquifers, is demonstrated to be technically feasible under the proposed operational cyclic profile examples. In addition, injecting hydrogen cushion gas before initiating the operational profiles enhanced the initial withdrawal performance; however, its advantages diminished over time. Despite conducting numerical simulations in a challenging and highly heterogeneous reservoir model, this enabled hydrogen recovery for energy production at the TWh-scale after an operational period of 10-years. It is important to emphasize that heterogeneity variations may struggling the reservoir performance, as verified in the results of this work, but they also help reducing the impacts of buoyancy forces and the vertical dispersion of hydrogen plumes through the heterogeneous and confining layering of the reservoir.

This work also highlights that while water production remains a significant challenge, its volumes can be substantially reduced by adopting hourly cyclic profiles compared to traditional seasonal cyclic profiles. However, hourly profiles necessitate more precise pressure management due to the rapid transitions between injection and withdrawal phases. Nonetheless, the lower instantaneous flow rates associated with hourly operations may enhance the long-term safety and stability of the storage complex. Comprehensive geomechanical studies, including an analysis of overburden layers, are essential to ensure caprock integrity under these conditions and should be addressed as proposed future works.

Although this study did not address potential hydrogen losses from reservoir chemical reactions, it is important to acknowledge that no optimization of well configuration or cushion gas pre-injection parameters was performed. Such optimization could significantly enhance hydrogen withdrawal volumes and overall efficiency. Key parameters, including well placement, perforation strategies, cushion gas injection duration, and flow rates, are critical to the success of hydrogen storage projects and should be tailored to the specific characteristics of each storage site.

Acknowledgments

The authors would like to thank the Portuguese Foundation for Science and Technology for funding H2GeoStore project (Doi: <https://doi.org/10.54499/2022.10650.PTDC>), and AspenTech and CMG for providing the software licenses used in the development of this work.

Generative AI and AI-assisted technologies

Generative AI and AI-assisted technologies have been used to improve the language and readability of this paper.

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Declaration of Interest Statement

The authors declare no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.