Introduction

With the global population and economic growth increasing, energy consumption is expected to increase, presenting a major challenge and urgency to address climate change. Key zero-carbon energy sources, including renewables and fossil fuels with carbon capture and storage (CCS), will be crucial. Additionally, sustainable energy storage solutions, like underground gas storage in porous media, are needed to balance intermittent renewables and ensure stable energy supply (Heinemann et al. 2021). Hydrogen is crucial in the shift towards sustainable, decarbonised energy systems. As a low-carbon energy carrier, it enhances energy security, cost-effectiveness, and reduces carbon emissions by diminishing reliance on fossil fuels (Heinemann et al. 2021). Hydrogen is efficient for large-scale renewable energy storage, with subsurface geological formations providing significant storage capacities essential for long-term grid stability and seasonal energy balancing and overcoming the storage capacity limitations of surface facilities. Geological storage is vital for cost-effective large-scale energy storage and integrating renewable hydrogen production (Raad et al. 2022).

Saline aquifers are promising for hydrogen storage due to their availability and substantial capacities, exceeding those of salt caverns. Their geographic accessibility and large storage volumes make them cost-effective for long-term storage and instrumental in the clean energy transition. They support hydrogen storage from renewable sources and leverage existing geological data and technology used in natural gas storage and CCS operations (Raad et al. 2022). Hydrodynamic modelling approaches for hydrogen storage in saline aquifers have been discussed in recent works (e.g., Sainz-Garcia et al. 2017); however, there is a lack of studies on the trapping (structural, stratigraphic, hydrodynamic) mechanisms and its efficiency to the overall storage process, which needs to minimise the dissolution, residual trapping (i.e., how much is trapped affects the commercial viability of the whole process) and cushion gas requirements. The impacts of integrating geological heterogeneities of petrophysical properties in multiple simulation scenarios, to realistically understand the complex behaviour of hydrogen in porous media, are still scarce in literature but its fully understanding is extremely important to avoid the under- or overestimations of these dynamic processes in the long-term storage, particularly due to the lack of existing commercial-scale projects on this topic.

The work presented herein is part of the R&D project "H2GeoStore – Hydrogen Geological Storage and Interactions in Porous Media of Subsurface Geology" and is focused on enhancing the understanding of hydrogen behaviour in porous media and the efficiency of operational processes, especially within saline aquifers.

Methods

The study encompasses extensive reservoir simulation studies, using the reservoir simulation software GEM of the Computer Modelling Group (CMG), based on realistic scenarios designed to reflect the energy surpluses and shortages from renewable sources from an analysis of the current energy system in Portugal. These scenarios were modelled by simulating the injection and withdrawal cycles of hydrogen over different time frames, such as seasonal and daily varying profiles. The seasonal profile is presented here, corresponding to a one-year cycle with seven blocks of constant flow rates within each block, as illustrated in Figure 1: an injection period of two months (59 days), followed by a shut-in period of three months (92 days), four withdrawal periods (122 days), with varying flow rates every month, and one last injection period of three months (92 days). The positive flow rates in Figure 1 corresponds to the injection volumes and the negative flow rates are the withdrawal volumes.

From the flow rates of the seasonal profile, well scenarios for the dynamic simulations were defined consisting in three distinct configurations. The first configuration (Figure 2b) consists in using separate hydrogen injection and withdrawal wells, the second (Figure 2c) is based on dual-purpose wells with conversion, and the third (Figure 2d) corresponds to a hybrid configuration, i.e., using both separate and dual-purpose wells with conversion for hydrogen injection and withdrawal processes. The expected (i.e., maximum) injection and withdrawal flow rates for the well scenarios are presented in Table 1. During the injection phase, the total injection flow rate is 1.85 million Sm^3/day, and the total withdrawal flow rates are 2.32 million Sm^3/day, 2.39 million Sm^3/day, 2.10 million Sm^3/day and 2.35 million Sm^3/day for each of the four months, respectively, during the withdrawal phase.

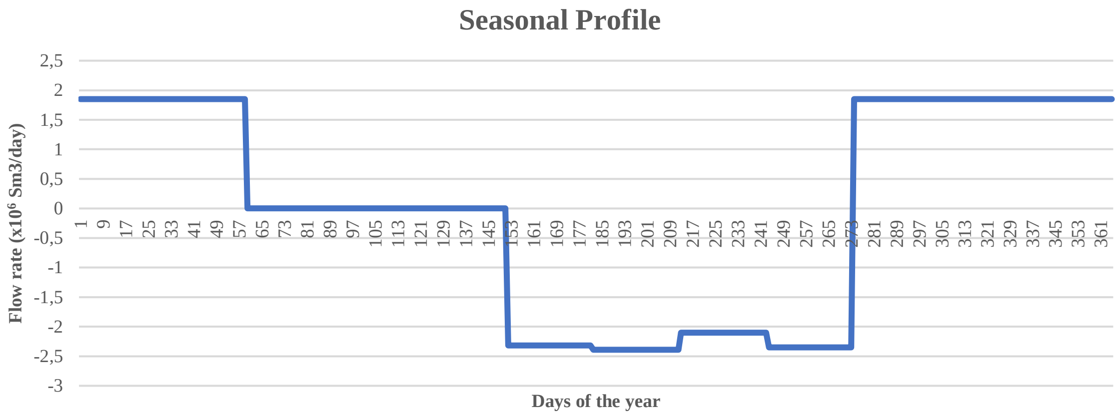

Figure 1 *Seasonal profile of the hydrogen operational cycle.*

The hydrogen operational cycle of Figure 1 is repeated to evaluate the reservoir efficiency based on total injected, stored and recovered hydrogen volumes at both operational cycle- and storage lifetime-scales (set as 10 years). This efficiency is influenced by various physical, chemical, and geological factors. In this work, the impacts of integrating physical phenomena in the simulation framework, such as hydrogen solubility, diffusivity and residual trapping, and the geological aspects, such as the reservoir heterogeneity, the spatial distribution of reservoir petrophysical properties (porosity and permeability), and the presence of cushion gas were considered. Due to the extension of this analysis, this paper presents the efficiency evaluation of the impacts of using cushion gas (hydrogen, in this case) over 9 months prior to the injection phase of the seasonal profile and compares with the results without using any cushion gas. The injection rates used for the cushion gas were the same as those presented in Table 1 for the injection phase of the seasonal profile.

Table 1 *Well scenarios and injection and withdrawal flow rates.*

Well scenarios		Separate configuration	Dual-purpose configuration	Hybrid configuration
Number of injection wells		5 injectors	6 injectors	4 + 2 injectors
Injection rates per well		370 000 Sm^3/day	308 333 Sm^3/day	308 333 Sm^3/day
Number of withdrawal wells		4 producers	6 producers	2 + 2 producers
Withdrawal rates per well	June	580 000 Sm^3/day	386 667 Sm^3/day	580 000 Sm^3/day
	July	597 500 Sm^3/day	398 333 Sm^3/day	597 500 Sm^3/day
	August	525 000 Sm^3/day	350 000 Sm^3/day	525 000 Sm^3/day
	September	587 500 Sm^3/day	391 667 Sm^3/day	587 500 Sm^3/day
Perforation thickness		100 m		

These operational scenarios were implemented in two realistic, heterogeneous reservoir models built to represent various structural environments. The first reservoir model consists in an antiform geological structure while the second reservoir model aims to reflect a more unconventional geological structure for underground gas storage. The latter model aims to represent a synform geological structure, with a syncline in the central sector of the model, and a pinchout and an anticlinal flank northwards and southwards, respectively, at the boundaries of the reservoir model. Although the three configurations of the well scenarios were conducted in the three sectorial areas of this model, only for the central sector (synclinal) is presented in this paper. The synform reservoir model has a grid size of 99x161x77 cells, with the horizontal cell thickness of 100m and the vertical cell thickness of 5m. This reservoir model is composed by two lithofacies, such as sand with interbedded clay layers, presenting the median values of 15% for effective porosity, and 334mD and 33mD for the horizontal and vertical permeability, respectively. The initial reservoir pressure and temperature follow a gradient increasing with depth, although the placement of the well scenarios in the model correspond to about 15MPa and 45ºC.

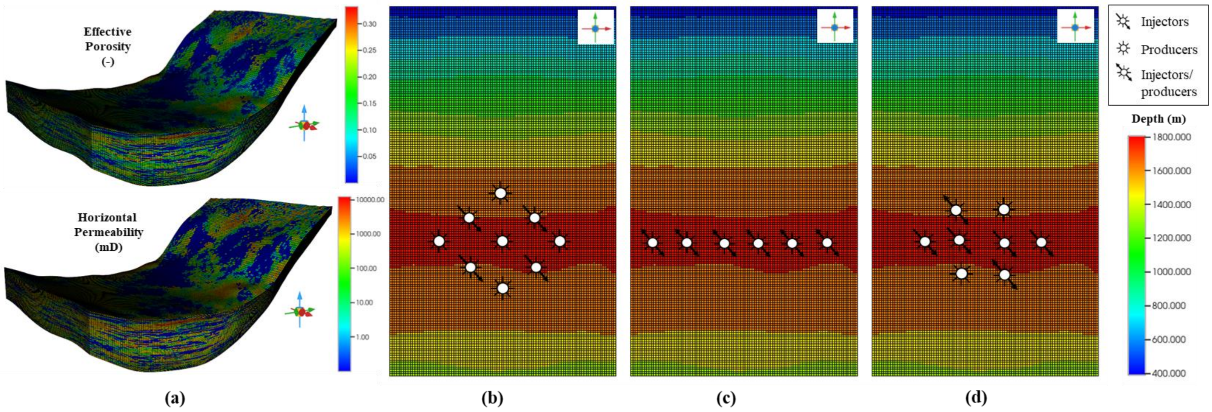

Figure 2 *a) 3D view of the reservoir models of effective porosity (top) and horizontal permeability (bottom), and the top view of the placement of well scenarios: b) separate configuration, c) dual-purpose configuration and d) hybrid configuration.*

Results

The results of this study were analysed in both well-by-well basis, for the injectors and producers of the well scenarios, and for all the grouping wells simultaneously (i.e., all the injector and producer wells). The parameters examined consisted of injected and produced gas rates, bottom hole pressure for the injection and withdrawal periods, water (brine) rates of the producer wells, water-gas ratios, and cumulative gas rates of injected and produced hydrogen volumes. These set of parameters, as well as the spatial-temporal evolution of pressure and hydrogen saturation in the reservoir, were investigated at each operational cycle and at the storage lifetime. The impacts of the reservoir heterogeneity are visible in the layering effects of the hydrogen saturation close to the wells, as illustrated in Figure 3 after 10 operational cycles for the well scenario of dual-purpose configuration (no cushion gas). It is important to note that the hydrogen saturation is relatively high not only due to the unrecoverable amounts of hydrogen in the reservoir, but also due to the injected volumes over the three months (October-December) of the injection phase (Figure 1) in the last cycle of the storage lifetime.

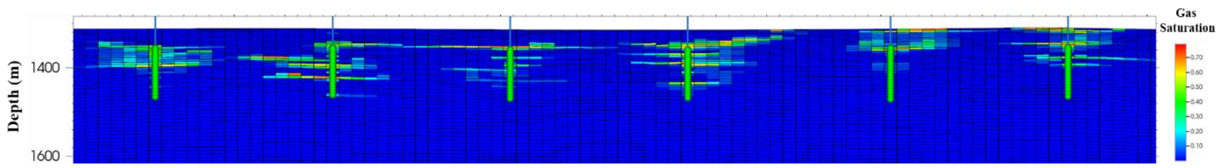

Figure 3 *Gas (hydrogen) saturation in the IK-2D plane 90 for the dual-purpose configuration of wells (no cushion gas) at the end of storage lifetime (December 2034). Refer to Figure 2c for the location of the wells.*

Figure 4 presents the cumulative gas (hydrogen) rates of the three well configuration scenarios with and without using cushion gas. The withdrawal of hydrogen volumes increases over time, even without considering the prior injection of the cushion gas. However, it is clear the well configuration strongly impacts the recovering of hydrogen volumes and, consequently, the reservoir performance. The dual-purpose configuration results in the best of the three configurations defined reaching an overall efficiency up to about 74%, comparing to the other two scenarios that present only about 30%. This is due to the best well scenario is not effectively dependent of the hydrogen migration from the location of the injector to the producer wells, as the hydrogen plumes are mainly displaced around the operational areas close to the dual-purpose wells. Considering the scenarios using cushion gas, the overall efficiency increases up to 10% for all the well configuration scenarios. After subtracting the cushion gas volumes, however, only the separate and hybrid configuration wells benefit of the prior gas injection, presenting an efficiency increase of about 5% while the efficiency of the dual-purpose wells remains the same as the same scenario without using the cushion gas. This suggests that this well configuration does not require the use of cushion gas or, ultimately, the cushion gas requirements must be optimised in terms of injection volumes and operational time of the injection period, particularly for the separate and hybrid well configurations.

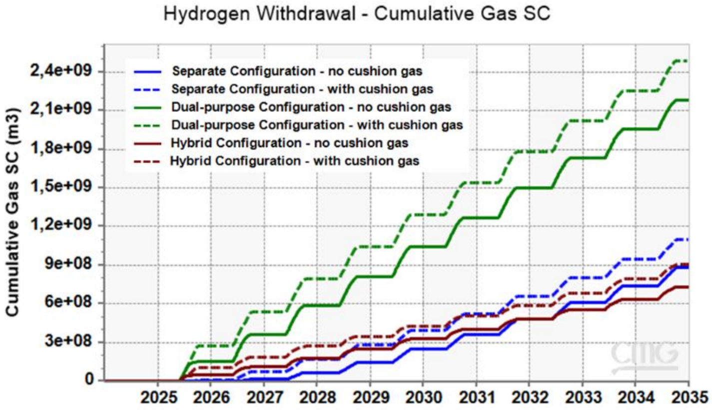

Figure 4 *Cumulative hydrogen withdrawal volumes at the end of the storage lifetime in this study.*

Conclusions

The work focuses on reservoir simulation for hydrogen geological storage in saline aquifers, showing that unconventional synform reservoirs could also be promising storage options. This study examines key aspects such as the integration of geo-engineering uncertainties, including various structural environments and complex heterogeneous reservoir models, and evaluates three well configuration scenarios to assess reservoir efficiency with prior cushion gas injection. The findings highlight that reservoir heterogeneity significantly impacts the efficiency of hydrogen injection and withdrawal cycles. The necessity of cushion gas is influenced by well configurations, with the dual-purpose well scenario showing higher efficiency where cushion gas plays a minimal role. Nonetheless, optimising the use of cushion gas is essential for cost-effective operations due to its substantial influence on reservoir efficiency.

The integration of thermal-hydraulic effects is currently ongoing in the project and will allow to further understand their spatial-temporal impacts during the cyclic processes. Future developments in this research project will also focus on the geochemical and geomechanical impacts on the integrity of various reservoir caprocks over the hydrogen storage lifetime.

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