

Full Length Article

Impacts of reservoir permeability anisotropy on hydrogen migration and recovery efficiency in geological storage[☆]Jinjiang Liu^{a,*}, David Dempsey^a, Andy Nicol^b, Matt Parker^b, Karan Titus^a^a Department of Civil and Natural Resources Engineering, University of Canterbury, Christchurch 8041, New Zealand^b School of Earth and Environment, University of Canterbury, Christchurch 8041, New Zealand

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ABSTRACT

Underground hydrogen storage (UHS) is a promising solution for large-scale, long-term energy storage by converting surplus renewable electricity into hydrogen for later use. Hydrogen recovery efficiency is an essential indicator for evaluating the performance of UHS. However, the impacts of permeability anisotropy, including horizontal permeability anisotropy ($k_{h,max}/k_{h,min}$) and horizontal-to-vertical permeability anisotropy (k_h/k_v), on hydrogen recovery efficiency have not been thoroughly investigated. This study addresses this gap with numerical simulations that couple a simplified box model and a field-realistic model based on the Ahuroa gas storage site.

Our results show that $k_{h,max}/k_{h,min}$ affects hydrogen recovery efficiency, and this effect becomes more pronounced at higher permeability. The difference in hydrogen recovery efficiency between $k_{h,max}/k_{h,min}=1$ and 10 expands from 1.3 percentage points at 100 mD to 4.3 percentage points at 200 mD. Increasing k_h/k_v can reduce the effect of $k_{h,max}/k_{h,min}$. In reservoirs with horizontal anisotropy, orienting a horizontal well along the minimum rather than the maximum permeability direction can reduce hydrogen recovery efficiency by up to 8 percentage points (from 78 % to 70 %), with all other conditions held constant. These findings from the box model were subsequently validated through simulations of a realistic geological site (Ahuroa natural gas storage site).

This study indicates that permeability anisotropy is an important consideration in UHS site assessment. Ignoring it can result in errors in hydrogen recovery efficiency evaluation, leading to inaccurate predictions of recoverable hydrogen volumes.

1. Introduction

Renewable energy sources, particularly wind and solar power, are playing an increasingly vital role in the global energy landscape [1,2]. However, their inherent variability often results in temporal mismatch between electricity generation and demand [3]. When electricity generation exceeds demand, the surplus energy needs to be stored for later use. Conversely, when demand exceeds generation, additional electricity from other sources is typically required to bridge the gap.

Wind and solar, as the fastest-growing renewable energy technologies, exhibit power output variability across a wide range of timescales, from minutes to seasons [4–6]. Short-term variability (ranging from minutes to days) can generally be managed using short-term storage systems, such as lithium-ion batteries or pressurized gas tanks. However, managing long-term (monthly to seasonal) variability requires storage

solutions with substantially larger capacities [7].

Underground hydrogen storage (UHS) has emerged as a promising solution for scalable long-term energy storage [8,9]. During periods of high renewable generation, surplus electricity can be converted into hydrogen and stored in the UHS site [10]. When electricity generation falls short of demand, the stored hydrogen can be retrieved and reconverted into electricity [11]. Beyond electricity balancing, stored hydrogen can also serve as a key feedstock for various industrial processes, including the production of methanol, ammonia, and synthetic fuels [10,12].

Hydrogen has a low volumetric energy density, approximately one-third that of methane under standard conditions [13]. Consequently, UHS requires roughly three times the reservoir volume of conventional underground gas storage (UGS) to store the same amount of energy. Given this high-volume requirement, depleted gas reservoirs are

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considered promising candidates for seasonal-scale hydrogen storage due to their large pore space, proven seal integrity, and pre-existing infrastructure [14].

Numerous studies have investigated the feasibility of storing hydrogen in depleted reservoirs [14–17]. Sari and Çiftçi [18] assessed the feasibility of hydrogen storage in an actual depleted gas field using numerical simulations. The simulation results indicate that depleted gas reservoirs can effectively maintain hydrogen purity while offering substantial storage capacity. Okoroafor et al. [19] evaluated several depleted fields in California based on multiple technical and geological criteria. Their analysis suggests that the depleted fields in California could provide sufficient capacity to store the hydrogen generated from curtailed renewable energy sources.

Because depleted reservoirs have been exploited over extended periods, their pressures are typically lower than original conditions. To maintain a certain withdrawal rate, cushion gas is generally injected in advance to support reservoir pressure [20,21]. Due to the high cost of hydrogen, economically viable alternatives such as carbon dioxide, nitrogen, or methane are commonly used as cushion gases. During the withdrawal stage, withdrawn gas is a mixture of hydrogen and cushion gas, resulting in reduced hydrogen purity [22]. Several studies have examined how the selection of cushion gas influence hydrogen recovery efficiency [20,22,23]. Kanaani et al. [22] investigated the influence of cushion gas type (carbon dioxide, nitrogen, and methane) on hydrogen recovery efficiency in a depleted oil reservoir. Their results indicate that hydrogen recovery efficiency decreases with increasing molecular weight of the cushion gas, primarily due to gravitational segregation. Among the examined cushion gases, methane achieved the highest hydrogen recovery efficiency, owing to its low density that limits gravitational separation from hydrogen during withdrawal. Similar findings were reported by Saeed & Jadhawar [20].

Permeability is a measure of the ability of a porous medium to transmit fluids under a pressure gradient [24,25]. It is a tensorial property that characterizes the ease with which fluids can flow in different spatial directions [26]. The directional dependence of permeability is referred to as permeability anisotropy [27]. Permeability anisotropy arises from various geological and structural factors, including macro-stratification, micro-stratification, and directional fracture, resulting in variations in permeability across different spatial directions [28–30]. Clavaud et al. [27] investigated permeability anisotropy using 18 rock samples representing different kinds of lithologies. In sandstones, anisotropy was found to be associated with bedding structures, whereas in volcanic rocks, it was primarily influenced by vesicle alignment and fracture orientation. In contrast, no consistent relationship was observed in limestones, likely due to the dominance of isolated porosity that does not contribute to effective hydraulic conductivity.

Permeability anisotropy in a reservoir system is commonly classified into two categories: (1) horizontal permeability anisotropy ratio ($k_{h,max}/k_{h,min}$), and (2) horizontal-to-vertical permeability anisotropy ratio (k_h/k_v) [31–33]. The ratio $k_{h,max}/k_{h,min}$ refers to the variability of permeability across the lateral extent of a reservoir. In conventional reservoir systems, the horizontal anisotropy ratio typically remains below 50 [34]. However, in naturally fractured reservoirs, this ratio could exceed 100 [35–37]. The ratio k_h/k_v is defined as the ratio of horizontal permeability to vertical permeability and is commonly used to quantify vertical anisotropy in porous media. Reported values of k_h/k_v typically range from 1 to 100 [38–41].

Permeability anisotropy affects the spatial distribution of injected fluid. Henderson and Pena [42] simulated viscous fingering in water–oil flow through anisotropic reservoirs. Their research revealed that in isotropic reservoirs, viscous fingers exhibit a tendency to elongate along preferential directions. In contrast, anisotropic reservoirs demonstrated a stabilizing effect on viscous fingering, with permeability anisotropy inhibiting the rapid development of immiscible viscous fingering and promoting more stable displacement patterns that benefit oil recovery.

Yu et al. [43] study the impact of permeability anisotropy ratio on carbon dioxide distribution in carbon capture and storage project. Simulation results indicate that lower k_h/k_v result in higher migration distance in vertical and horizontal directions. Because under lower k_h/k_v , carbon dioxide reached the caprock earlier and then flow laterally beneath the caprock.

The performance of UHS is also influenced by the design of well configuration [14,44,45]. Sun et al. [45] proposed an approach called gravity-assisted-storage-extraction (GASE) protocol to increase hydrogen recovery efficiency during UHS. This method leverages the buoyant nature of hydrogen. Hydrogen is injected through a vertical well at the bottom of the reservoir and withdrawn from horizontal well at the top layer. Compared to the conventional single-well injection–production scheme, new method improves hydrogen recovery efficiency by 20–30 %. Ramsari et al. [21] analysed the influence of well configurations on hydrogen recovery efficiency and hydrogen purity in a depleted reservoir. Four types of well configurations were investigated. Due to the low molecular weight of hydrogen, the highest recovery efficiency was achieved when both injection and production were conducted through horizontal wells.

In previous studies on UHS, the impact of permeability anisotropy on hydrogen recovery efficiency has been examined, but most of these studies only focus on k_h/k_v [46,47]. However, $k_{h,max}/k_{h,min}$ is also common in many geological formations [27,48]. This form of anisotropy affects gas flow ability in different horizontal directions and can consequently influence hydrogen recovery efficiency. In addition, the influence of factors such as reservoir thickness, average permeability, and well configuration on hydrogen recovery efficiency may vary depending on the degree of permeability anisotropy. As such, neglecting anisotropic permeability in site evaluations may lead to inaccurate assessments of UHS performance and suitability.

To address this research gap, a simplified box model was developed to investigate the effect of permeability anisotropy on the performance of UHS. Furthermore, the coupled impacts between permeability anisotropy and reservoir thickness, average permeability, and well configuration were systematically analysed to provide a more comprehensive understanding of their influence on UHS performance. Subsequently, the findings were validated using a field-scale model based on the Ahuroa gas storage facility. The insights obtained from this study can provide guidance for hydrogen storage site evaluation, leading to more accurate assessment procedures.

2. Methods

2.1. Numerical simulation

The governing mass conservation equations used in the model are [26]:

$$\frac{\partial}{\partial t} \left(\phi \sum_{j=1}^{n_p} x_{ij} S_j \eta_j \right) - \nabla \cdot \sum_{j=1}^{n_p} (x_{ij} \mathbf{u}_j \eta_j + \phi S_j D_j \eta_j \nabla x_{ij}) + Q_i = 0 \quad (1)$$

Where ϕ is porosity, dimensionless; n_p is the number of phases; j is an index denoting the phase, $j = 1 \dots n_p$; n_c is the number of components; i is an index denoting the component, $i = 1 \dots n_c$; x_{ij} is the mole fraction of component i in phase j , dimensionless; S is the saturation of phase j , dimensionless; η_j is the molar density of phase j , mol/m³; $\mathbf{u}_j$ is the flow velocity of phase j , m/s; D_j is the diffusion coefficient of phase j , m²/s; Q_i is the source/sink term of component i , mol/(m³ • s).

The velocity of phase j in the porous media is given by Darcy's equation:

$$\mathbf{u}_j = - \frac{k k_{rj}}{\mu_j} (\nabla P_j - \rho_j \mathbf{g} \hat{\mathbf{z}}) \quad (2)$$

Where k is the absolute permeability, m²; k_{rj} is the relative

permeability of phase j ; μ_j is viscosity, Pa.s; P_j is fluid pressure of phase j , MPa; ρ_j is the mass density of phase j , kg/m³; g is the gravitational constant, m/s²; $\hat{z}$ is a unit vector in the direction of gravity.

For gas–liquid diffusion at the gas–water interface, the diffusion coefficient is 2×10^{-9} m²/s. For gas–gas diffusion in the gas phase, the diffusion coefficient is 2×10^{-5} m²/s.

The density and viscosity of the gas mixture are given as follows:

$$\eta = X_a \eta_a + X_b \eta_b \quad (3)$$

$$\mu = X_a \mu_a + X_b \mu_b \quad (4)$$

Where X is mole fraction of different gas components, and a, b are the two gas components (natural gas and hydrogen).

The density and enthalpy of hydrogen and natural gas are calculated using the GERG 2008 equation of state [49]. The viscosity of hydrogen and natural gas are calculated using the Lorenhz-Bray-Clay method [50] and a residual entropy method respectively [51].

Gas and water relative permeability curves were calculated based on the modified Corey relative permeability model [52].

$$k_{rw} = k_{rw,max} \left(\frac{S_w - S_{wr}}{1 - S_{wr} - S_{gr}} \right)^{n_w} \quad (5)$$

$$k_{rg} = k_{rg,max} \left(1 - \frac{S_g - S_{gr}}{1 - S_{wr} - S_{gr}} \right)^{n_g} \quad (6)$$

Where k_{rw} is the relative permeability of water; $k_{rw,max}$ is the maximum relative permeability for water; S_w is water saturation; S_{wr} is residual water saturation; k_{rg} is the relative permeability of gas; $k_{rg,max}$ is the maximum relative permeability for gas; S_g is gas saturation; S_{gr} is residual gas saturation; n_w is water exponent; n_g is gas exponent.

Our model has been implemented in the reservoir simulator OpenGoSim. OpenGoSim is an open-source reservoir simulator for multiphase, multicomponent flow and transport in porous material, built on the PFLOTTRAN framework [53–55]. It enables large-scale parallel computing. Sheikhi & Flynn (2024) investigated hydrogen migration and mixing in a depleted gas reservoir with a low permeability interbed [53]. Compositional simulations were conducted using OpenGoSim and CMG, and the two simulators produced closely matching results. More detailed information and validation benchmarks are provided in [54,55].

2.2. Box model

To evaluate the impact of permeability anisotropy on hydrogen

storage performance, we developed a box model representing a depleted gas reservoir. The following assumptions were made in the simulations. The assumptions include:

- (1) Solubility of hydrogen and cushion gas in brine were neglected.
- (2) No chemical or biochemical reactions was considered in the simulation.
- (3) Capillary pressure is ignored.

The model represents a reservoir with a top depth of 2100 m. The model is bounded by no-flow conditions on all six faces. The model dimensions are $1000 \times 1000 \times 50$ m³ (grid block size: $20\text{m} \times 20\text{m} \times 2\text{m}$). A detailed sensitivity analysis of grid sizes is provided in Appendix A. To enable detailed analysis, the reservoir model was divided vertically into five equal layers (Layer 1 to Layer 5 from top to bottom), each 10 m thick and with identical properties (Fig. 1).

To facilitate subsequent comparison and analysis, a baseline model was established. In the baseline model, the reservoir permeability and porosity are set to 100 mD and 15 %, respectively. Permeability is assumed to be isotropic, with identical values in all three directions ($k_h/k_v = k_{h,max}/k_{h,min} = 1$). The initial reservoir temperature and pressure were set to 70°C and 16 MPa. Only a single well located at the centre of the reservoir is considered. It is perforated across all layers. Pure hydrogen is used in the simulation, while the natural gas in the reservoir is composed of 94.0 % methane, 4.5 % nitrogen, and 1.5 % carbon dioxide.

The relative permeability curves shown in Fig. 2 were calculated using the Brooks-Corey functions, with the corresponding parameter values listed in Table 1. Additional parameters used in the simulation were also detailed in Table 1.

2.3. Simulation setup

The UHS simulation consists of two stages, including cushion gas injection stage and cyclic operation stage. In the cushion gas injection stage, cushion gas is injected at the rate of 5×10^5 Sm³/day for 360 days. Cushion gas is natural gas, with the same compositions of initial natural gas in the reservoir. After injecting cushion gas, 10 injection-withdrawal cycles were implemented. Each cycle includes 90 days injection stage and 90 days withdrawal stage. Injection and withdrawal rates are 1×10^6 Sm³/day (Fig. 3).

During the injection-withdrawal cycles, bottomhole pressure (BHP) was maintained within the range of 16 to 24 MPa. The minimum bottomhole pressure is to ensure gas deliverability and the maximum bottomhole pressure is to avoid induced seismicity. The injection rate was

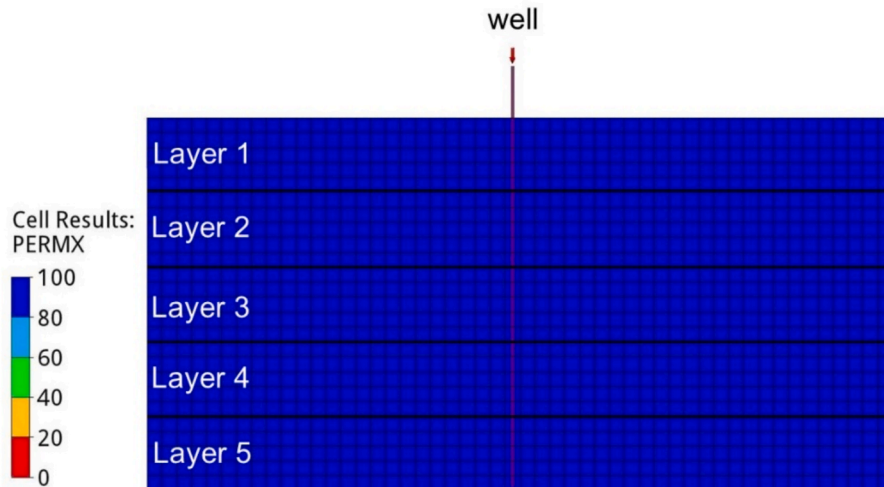


Fig. 1. Schematic diagram of the box model. The black line represents the interface between layers, and PERMX indicates permeability in x-direction.

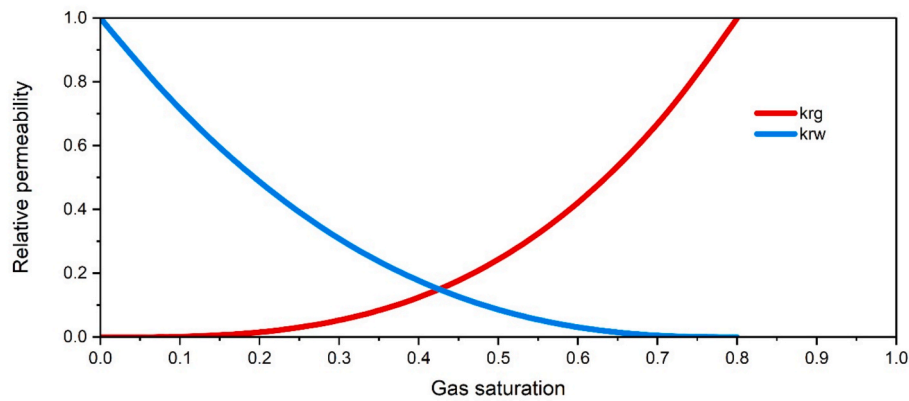


Fig. 2. Relative permeability curves used in the reservoir simulation. Red line represents gas relative permeability curve, blue line represents water relative permeability curve (Chai et al. [54]).

Table 1

Parameters input in the baseline model.

Parameters	Unit	Value
Reservoir permeability	mD	100
Reservoir porosity	Dimensionless	0.15
Initial pressure	MPa	16
Initial temperature	°C	70
Gas-gas diffusion	m ² /s	2×10^{-5}
Gas-liquid diffusion	m ² /s	10^{-9}
Residual water saturation	Dimensionless	0.2
Residual gas saturation	Dimensionless	0.05
Water exponent for modified Brooks-Corey functions	Dimensionless	2.5
Gas exponent for modified Brooks-Corey functions	Dimensionless	3
Maximum relative permeability for water in modified Brooks-Corey functions	Dimensionless	1
Maximum relative permeability for gas in modified Brooks-Corey functions	Dimensionless	1

reduced when bottomhole pressure approached the maximum allowable pressure (24 MPa), while the production rate was adjusted downward during the withdrawal as bottomhole pressure approached the minimum allowable pressure (16 MPa).

To investigate the impact of permeability anisotropy on UHS performance, a baseline model (isotropic case) and several comparison models (anisotropic cases) were developed. The study primarily focused on two key aspects: k_h/k_v and $k_{h,max}/k_{h,min}$. In the simulation conducted to investigate the impact of $k_{h,max}/k_{h,min}$, the maximum horizontal permeability ($k_{h,max}$) and minimum horizontal permeability ($k_{h,min}$) are assigned along the x- and y- directions. At the same time, maintain the

average permeability, defined as $\sqrt{k_{h,max} \cdot k_{h,min}}$, constant as in the baseline model. The vertical permeability remains unchanged and is equal to that in the baseline model. In the simulation designed to assess the impact of k_h/k_v , the vertical permeability k_v is reduced based on k_h/k_v , while the horizontal permeabilities in both the x- and y-directions remain equal to those in the baseline model (Table 2).

In addition to investigating the impact of anisotropy, this study also investigated its coupled effects with formation thickness and with average permeability to quantify their respective influences on hydrogen recovery efficiency. Furthermore, six different well configurations were analysed across reservoirs with varying degrees of anisotropy to assess the impact of engineering design on recovery performance.

3. Simulation results

3.1. Impact of horizontal-to-vertical permeability anisotropy ratio

To investigate the impact of k_h/k_v on hydrogen recovery efficiency,

Table 2

Summary of anisotropy factors used in the simulations.

Case	$k_{h,max}/k_{h,min}(-)$	$k_h/k_v(-)$	$k_{h,max}$ (mD)	$k_{h,min}$ (mD)	k_v (mD)
1 (Baseline)	1	1	100	100	100
2	1	5	100	100	20
3	1	10	100	100	10
4	1	100	100	100	1
5	5	1	223.6	44.7	100
6	10	1	316.2	31.6	100

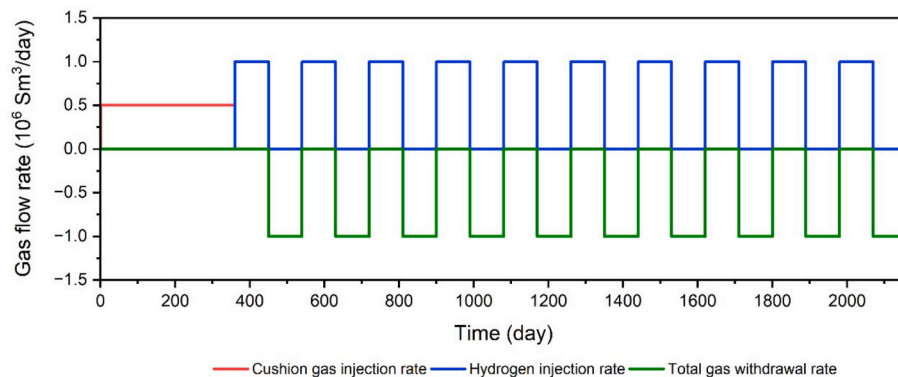


Fig. 3. Injection and withdrawal rates at different stages in the baseline model. The red line represents the cushion gas injection rate, the blue line represents the hydrogen injection rate, and the green line represents the total gas withdrawal rate.

in addition to the isotropic baseline model (Case 1), three anisotropic cases were developed with k_h/k_v ratios of 5, 10, and 100 (Cases 2, 3, and 4). All other parameters were kept consistent with those in the isotropic baseline model to isolate the influence of k_h/k_v .

Fig. 4 presents vertical cross-sectional views of hydrogen mole fraction in the gas phase under varying k_h/k_v . Fig. 4 a–d illustrate the hydrogen distribution at the end of the first injection stage, with k_h/k_v ranging from 1 (isotropic) to 100. When $k_h/k_v = 1$, the hydrogen plume exhibits a distinct cone-shaped geometry. The extent of the hydrogen front decreases from the top to the bottom layer. As the anisotropy ratio increases to 100, the hydrogen front becomes more uniform, meaning hydrogen in each layer flows away from the wellbore at a similar rate. Fig. 4 e–h illustrates the vertical cross-sectional views of hydrogen distribution at the end of the simulations under varying k_h/k_v . Although the hydrogen plumes exhibit cone-shaped geometry in all four cases, clear differences are observed with increasing k_h/k_v . With the increase of k_h/k_v , the upward migration of hydrogen is increasingly restricted due to lower vertical permeability. This results in more hydrogen retained in the lower layers, while the lateral extent and hydrogen concentration in the top layers are reduced.

With the increasing k_h/k_v , hydrogen purity in each layer shows different trends (Fig. 5). For the top layer (Layer 1), with the increasing k_h/k_v , hydrogen purity decreases. But after three cycles, the hydrogen purity difference is not very pronounced. For the lower layers (Layer 3, 4, and 5), hydrogen purity increases with the increase of k_h/k_v . Hydrogen purity in Layer 2 does not change much. At the same time, because of the different variation trends in each layer, the difference in hydrogen purity among layers decreases as k_h/k_v increases. As shown in Fig. 5, the curves of hydrogen purity in different layers become closer with the increasing k_h/k_v , indicating a more uniform vertical distribution of hydrogen. This is mainly because a higher k_h/k_v reduces the influence of gravity override.

As the horizontal permeability and pressure distribution are identical across all layers, compared with hydrogen purity, there is less variation in the total gas withdrawal rates among them (see Fig. B1). When k_h/k_v

$= 1$, although the hydrogen concentration in the top layer is high, the total gas withdrawal rate from this layer is constrained, and thus the high concentration does not result in a higher hydrogen withdrawal rate. In contrast, the lower layers contain less hydrogen, leading to a reduced hydrogen withdrawal rate under similar total gas withdrawal rate. When k_h/k_v increases to 100, the hydrogen concentration in the top layer slightly decreases but remains high. Since the total gas withdrawal rate in this layer remains nearly unchanged, the hydrogen withdrawal rate is only marginally affected. However, in the lower layers, the increased hydrogen concentration enhances the hydrogen withdrawal rate, thereby improving the overall hydrogen recovery efficiency. Influence of k_h/k_v on hydrogen recovery efficiency at the end of simulation was shown in Fig. 6.

3.2. Impact of horizontal permeability anisotropy ratio

To investigate the impact of $k_{h,max}/k_{h,min}$ on hydrogen recovery efficiency, in addition to the isotropic baseline model (Case 1), three anisotropic cases were developed with $k_{h,max}/k_{h,min}$ ratios of 5 and 10 (Cases 5 and 6).

Fig. 7 presents the top and side views of the hydrogen mole fraction distribution in the gas phase under different horizontal permeability anisotropy ratios ($k_{h,max}/k_{h,min}$). In the baseline model ($k_{h,max}/k_{h,min} = 1$), the hydrogen distribution on the horizontal plane exhibits a circular pattern, indicating that hydrogen migrates uniformly in all directions around the wellbore. As the anisotropy ratio increases from 1 to 10, the distribution gradually transitions from circular to elliptical, with hydrogen predominantly migrating along the direction of maximum horizontal permeability. These results indicate the influence of permeability anisotropy on the spatial distribution of hydrogen.

Fig. 8 illustrates hydrogen purity in each layer under varying $k_{h,max}/k_{h,min}$. With increasing $k_{h,max}/k_{h,min}$, hydrogen purity in the top layer remains almost unchanged, while it increases in the other layers. The change trend of hydrogen purity in each layer is similar to those in the k_h/k_v cases. As shown in Fig. 9, with increasing cycle numbers, the

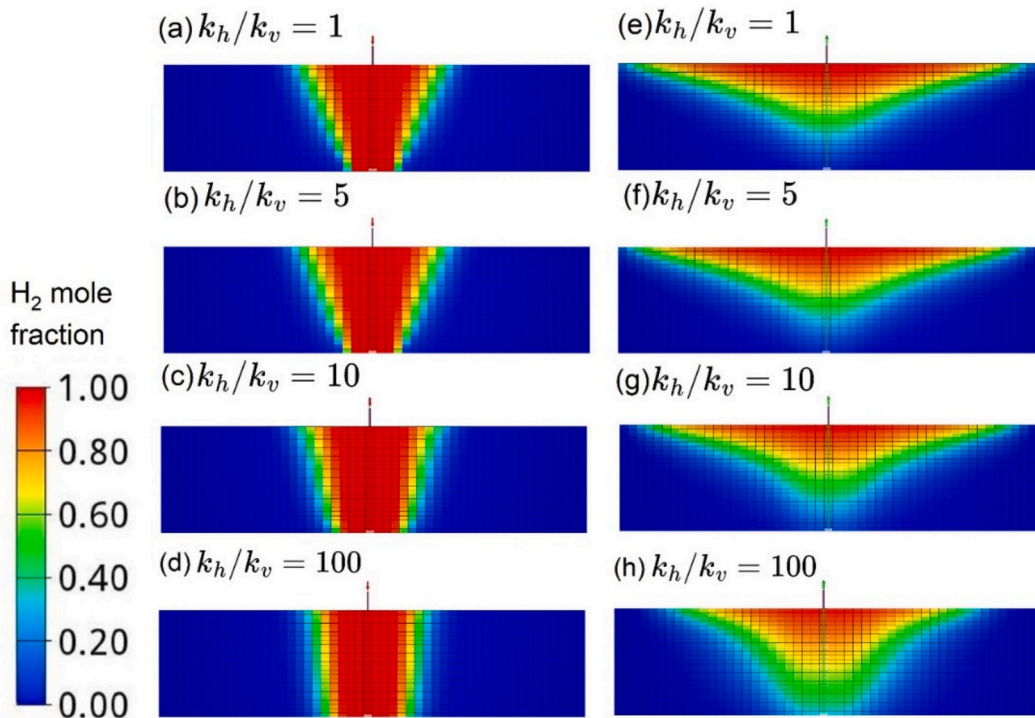


Fig. 4. Spatial distribution of hydrogen mole fraction in the gas phase: (a–d) End of first injection stage with k_h/k_v of 1, 5, 10, and 100, (e–h) End of simulation period with corresponding k_h/k_v of 1, 5, 10, and 100. Colour bar indicates the mole fraction of hydrogen in the gas phase.

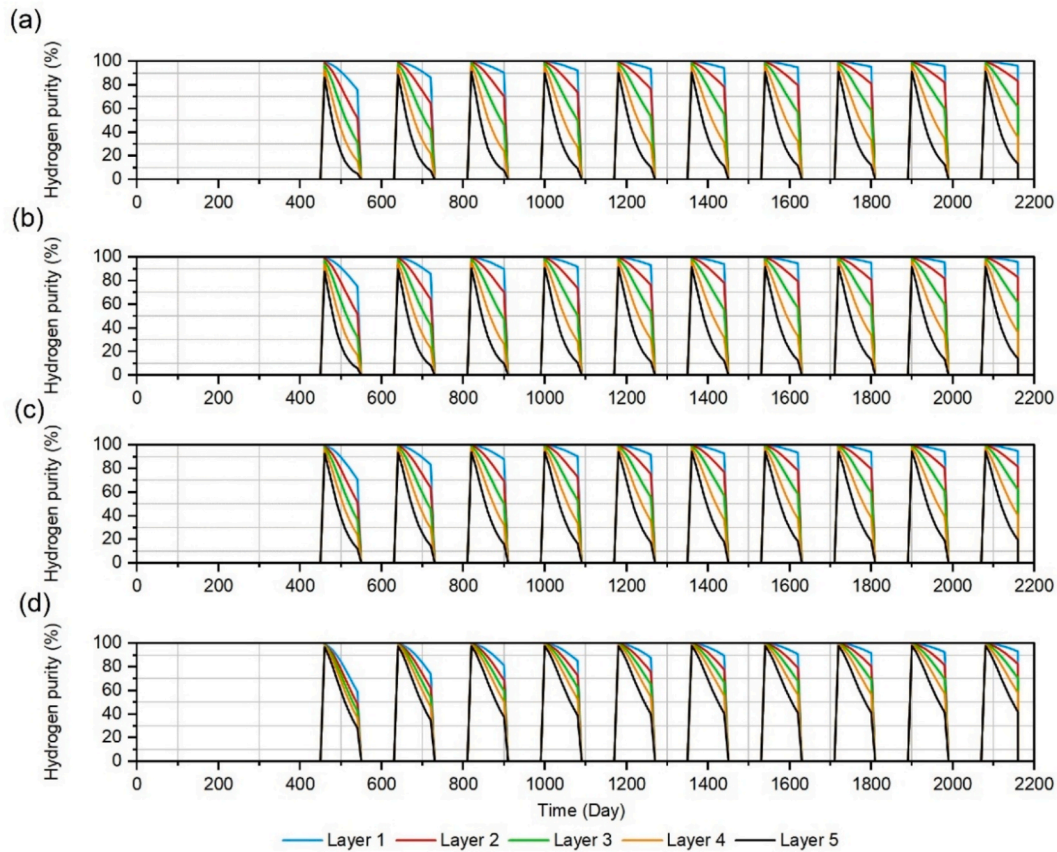


Fig. 5. Hydrogen purity across reservoir layers under varying horizontal-to-vertical permeability anisotropy ratios (k_h/k_v): (a) = 1, (b) = 5, (c) = 10, (d) = 100. Colors represent different layers: blue for Layer 1, red for Layer 2, green for Layer 3, yellow for Layer 4, and black for Layer 5.

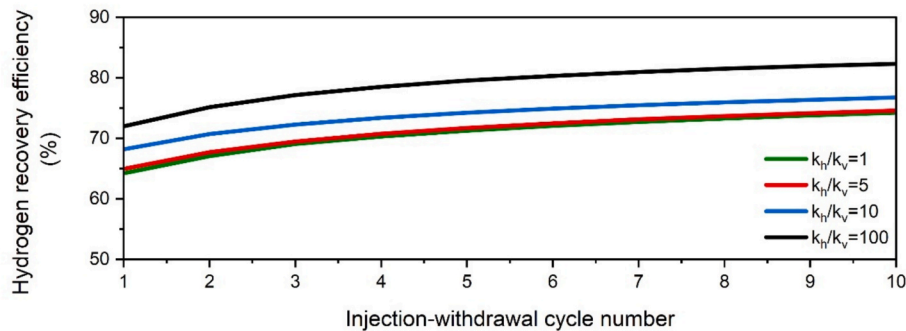


Fig. 6. Hydrogen recovery efficiency under varying horizontal-to-vertical permeability anisotropy ratios (k_h/k_v): 1, 5, 10, and 100, represented by green, red, blue, and black lines.

hydrogen recovery efficiency in anisotropic reservoirs gradually surpasses that in isotropic reservoirs. Compared with isotropic model, the final hydrogen recovery increases by 0.5 % and 1.3 % when $k_{h,max}/k_{h,min} = 5$ and 10 (Fig. 9).

3.3. Impact of geologic characteristics

In the geological assessment for UHS site, reservoir thickness and average permeability are two important factors [56,57]. In this section, we investigate how permeability anisotropy affects the extent to which reservoir thickness and average permeability influence hydrogen recovery efficiency.

To study the impact of reservoir thickness, two comparison models were constructed with thickness of 40 m and 60 m. To minimize the

impact of gas flow rate, both injection and withdrawal rates were set to $2 \times 10^4 \text{ Sm}^3/\text{day}/\text{m}$ for the comparison models, corresponding to total rates of 8×10^5 and $12 \times 10^5 \text{ Sm}^3/\text{day}$. This ensures that the injection and withdrawal rates remain consistent per unit thickness across all models.

Fig. 10 illustrates hydrogen mole fraction in the gas phase at the end of simulation in the isotropy model ($k_{h,max}/k_{h,min} = 1$ and $k_h/k_v = 1$). A notable difference is observed in the extent of the low-concentration zone: in the 60 m-thick reservoir, approximately 10 m at the bottom exhibits a hydrogen mole fraction below 10 %, whereas in the 40 m-thick reservoirs, this zone is limited to only 2 m. This indicates that in isotropic reservoirs, increasing thickness leads to a larger under-swept zone at the bottom, which contributes to the reduction in overall hydrogen recovery.

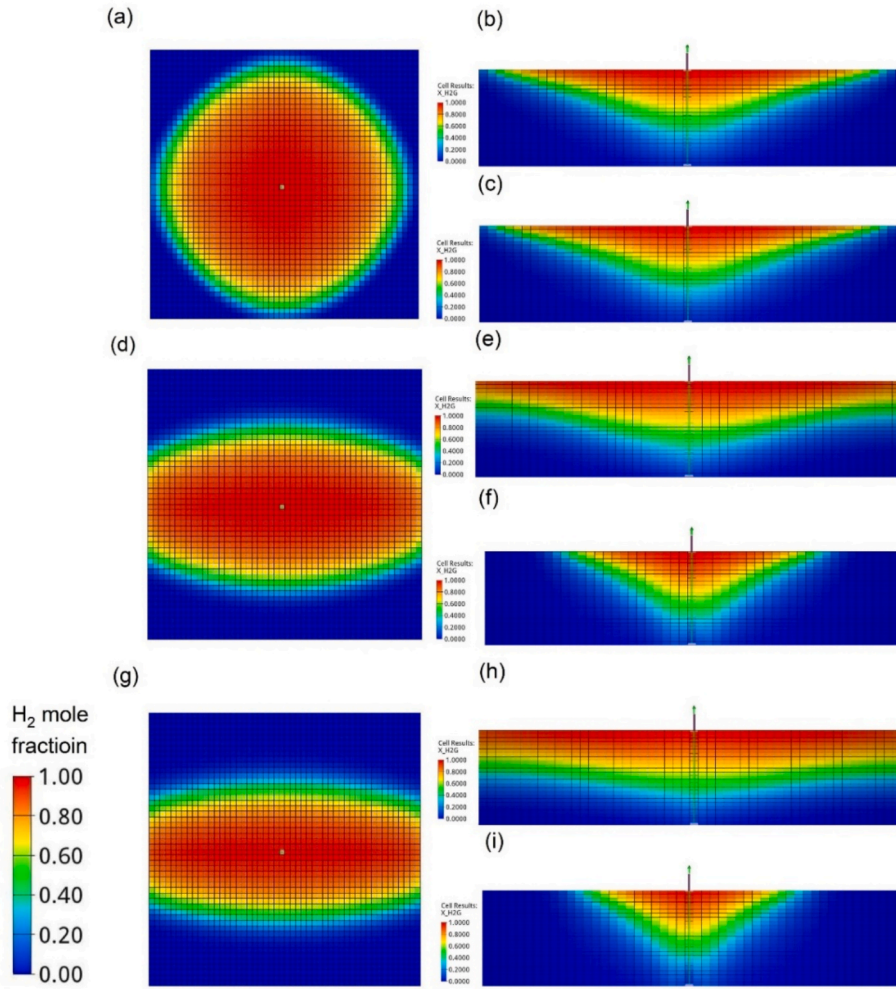


Fig. 7. Hydrogen mole fraction distributions in the gas phase under varying horizontal permeability anisotropy ratios ($k_{h,max}/k_{h,min}$): (a-c) = 1, (d-f) = 5, (g-i) = 10. (a), (d), and (g) show top-view distributions, where the left-right direction corresponds to the direction of $k_{h,max}$ (X-axis), while (c), (f), and (i) show vertical sections along the direction of $k_{h,min}$ (Y-axis).

Similar trend was found in the anisotropy models. Fig. 11 shows hydrogen recovery efficiency under different permeability anisotropy. Hydrogen recovery efficiency decreases with increasing reservoir thickness under fixed values of $k_{h,max}/k_{h,min}$ and k_h/k_v . However, the recovery difference caused by thickness becomes less pronounced as permeability anisotropy increases. When $k_{h,max}/k_{h,min}$ increases from 1 to 10, the hydrogen recovery efficiency difference between the 40 m and 60 m reservoirs reduces from 5 % to 3 %. Similarly, increasing k_h/k_v from 1 to 100 narrows this gap from 5 % to 1 %.

To investigate the influence of reservoir average permeability (k_{ave}), we extended our analysis by creating two additional cases, with average permeabilities of 50 and 200 mD. For each case, we considered different $k_{h,max}/k_{h,min}$ and k_h/k_v ratios while keeping the average permeability constant. The simulation results were depicted in Fig. 12.

Under constant k_h/k_v , with increasing average permeability, the hydrogen recovery efficiency for the strongly anisotropic case (high $k_{h,max}/k_{h,min}$) progressively surpasses that for the weakly anisotropic case. When $k_h/k_v = 1$ and $k_{ave} = 50$ mD, hydrogen recovery efficiency at $k_{h,max}/k_{h,min} = 1, 5$, and 10 are 81 %, 81 %, 80 %. When k_{ave} increase to 200 mD, these efficiencies decrease to 64 %, 66 %, and 68 %. For constant $k_{h,max}/k_{h,min}$ and k_{ave} , hydrogen recovery efficiency increases with increasing k_h/k_v , and the magnitude of this increase is amplified as k_{ave} rises. When $k_{h,max}/k_{h,min} = 1$ and $k_{ave} = 50$ mD, hydrogen recovery efficiency at $k_h/k_v = 1, 10$, and 100 are 81 %, 82 %, 85 %. When k_{ave}

increase to 200 mD, these efficiencies decrease to 64 %, 67 %, and 77 %.

3.4. Impact of well configuration

Well configuration plays a critical role in the design of UHS, as it influences gas migration pathways and recovery efficiency. In this section, we evaluate the performance of six representative well configurations under different types of permeability anisotropy (Fig. 13).

The fully perforated injection-withdrawal vertical well (FP-V) is defined as a single vertical well perforated along the entire reservoir thickness, enabling both injection and production through the same wellbore. The upper-zone injection-withdrawal vertical well (UP-V) refers to a vertical well perforated only in the upper part of the reservoir, allowing injection and withdrawal operations limited to higher-permeability strata. The injection-withdrawal horizontal wells aligned with maximum and minimum permeability (H-MAX and H-MIN) refer to single horizontal wells completed in the upper zone of the reservoir, performing both injection and withdrawal. Their orientations are parallel to the directions of maximum and minimum horizontal permeability, respectively. The vertical injection well combined with horizontal withdrawal wells aligned with maximum and minimum permeability (FP-V-I / H-MAX-P and FP-V-I / H-MIN-P) refer to dual-well configurations in which injection is carried out through a vertical well, while withdrawal is conducted through a horizontal well oriented along the directions of maximum and minimum horizontal permeability.

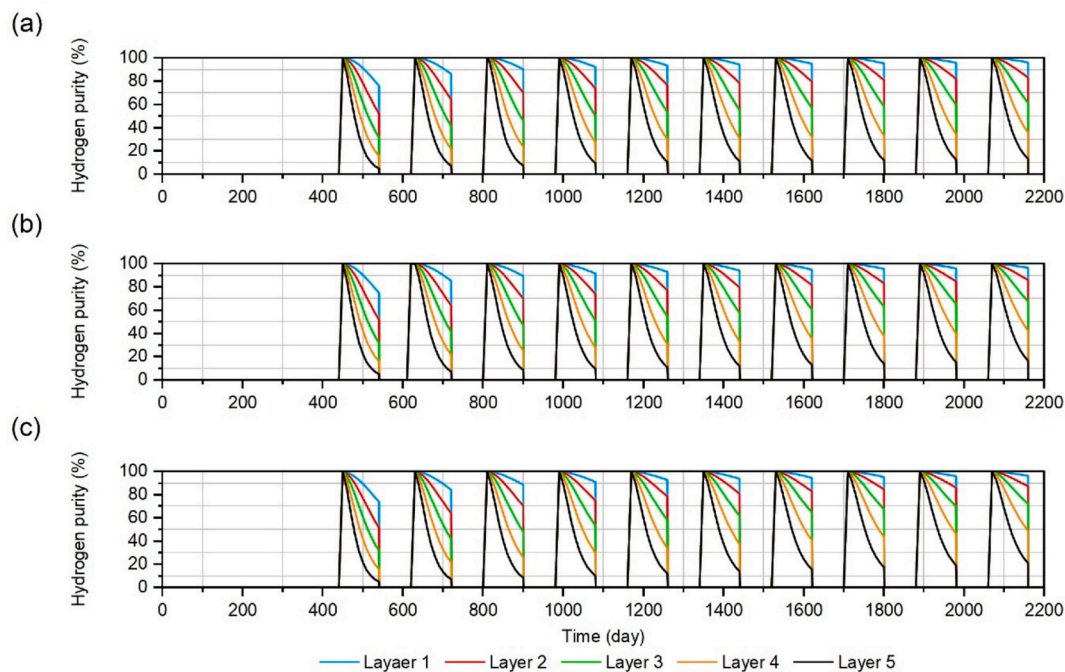


Fig. 8. Hydrogen purity across reservoir layers under varying horizontal permeability ratios ($k_{h,max}/k_{h,min}$): (a) 1, (b) 5, (c) 10. Blue: Layer 1; Red: Layer 2; Green: Layer 3; Yellow: Layer 4; Black: Layer 5.

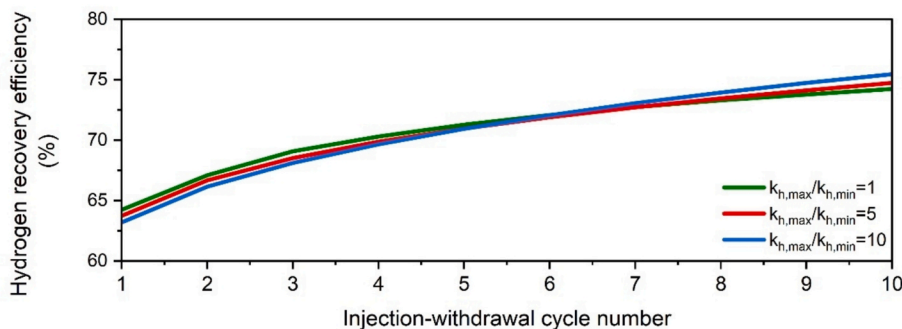


Fig. 9. Hydrogen recovery efficiency under varying horizontal permeability anisotropy ratios ($k_{h,max}/k_{h,min}$): 1, 5, and 10, represented by green, red, blue, and black lines.

Fig. 14a presents the simulation results for various well configurations under different k_h/k_v ratios. As the k_h/k_v ratio increases, the hydrogen recovery efficiency of vertical injection combined with horizontal withdrawal wells (FP-V-I/H-MAX-P and FP-V-I/H-MIN-P) initially rises and subsequently declines. In contrast, for all other well configurations, hydrogen recovery efficiency increases with increasing k_h/k_v ratio.

This occurs because hydrogen injected into the lower layers encounters resistance when attempting to migrate upward due to the extremely low vertical permeability. Therefore, for reservoirs characterized by high k_h/k_v ratios, vertical injection and horizontal withdrawal well configurations are not recommended. On the other hand, when k_h/k_v reaches 100, although the hydrogen recovery efficiency remains unchanged for the top-layer injection well configuration (UP-V, H-MAX, and H-MIN), the range of pressure variation becomes different. The vertical well demonstrates a larger pressure fluctuation range than the horizontal well (see Fig. C1).

Fig. 14b presents the simulation results for various well configurations under different $k_{h,max}/k_{h,min}$ ratios. In reservoirs with horizontal anisotropy, the orientation of horizontal wellbores is a crucial influencing factor. For well configurations with horizontal wells, including

injection-withdrawal horizontal wells or vertical injection well combined with a horizontal withdrawal well, aligning the horizontal well with the direction of maximum permeability yields higher hydrogen recovery efficiency than alignment with the direction of minimum permeability, with all other conditions held constant.

4. Real geological model

While the simplified box model effectively illustrates the influence of permeability anisotropy, we conducted a more comprehensive investigation using a realistic geological model based on field data from the Ahuroa site to demonstrate the practical significance of our findings in actual geological settings.

4.1. Geological model

The Ahuroa gas field is located onshore in New Zealand's Taranaki region, approximately 14 km northeast of Stratford (Fig. 15). It was discovered in November 1986 and remained in production until 2008. Over this period, it yielded approximately 1.22×10^9 Sm³ of gas, 1.73×10^5 m³ of oil, and 6.1×10^4 m³ of water. In 2008, the field was

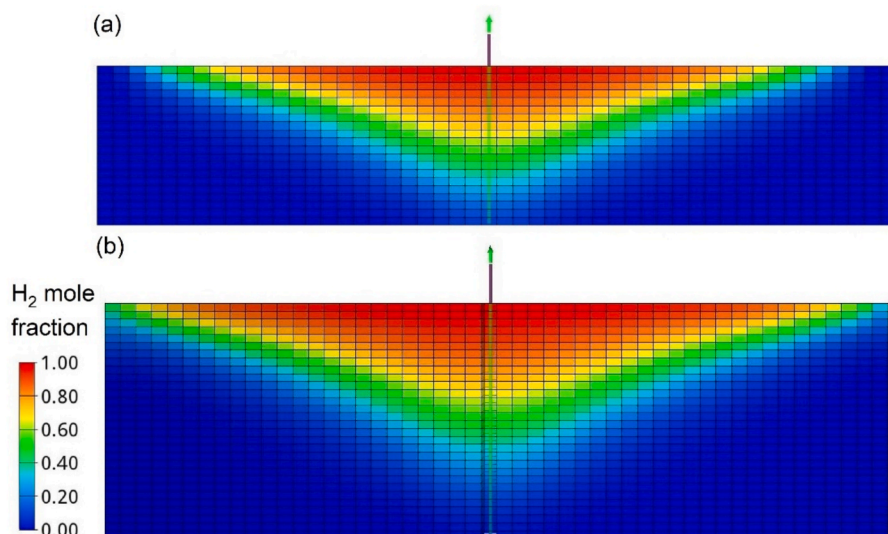


Fig. 10. Hydrogen mole fraction in the gas phase at the end of simulation in the isotropy model. (a) reservoir thickness = 40 m; (b) reservoir thickness = 60 m.

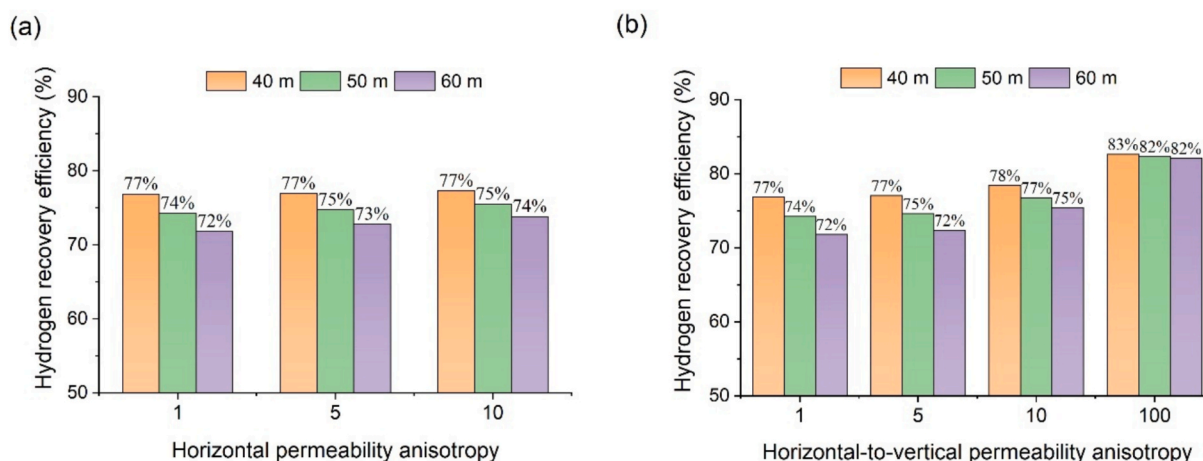


Fig. 11. Hydrogen recovery efficiency under varying reservoir thickness and permeability anisotropy: (a) recovery efficiency with different horizontal permeability anisotropy ratios ($k_{h,max}/k_{h,min} = 1, 5$, and 10); (b) recovery efficiency with varying horizontal-to-vertical permeability anisotropy ratios ($k_h/k_v = 1, 5, 10$, and 100). Each case is evaluated under three reservoir thicknesses: 40 m (orange), 50 m (green), and 60 m (purple).

repurposed as a natural gas storage facility, which remains operational to this day. In this study, a hypothetical hydrogen storage scenario is evaluated based on the geological conditions at the Ahuroa site. More information can be found in Liu et al. [55].

Fig. 16 illustrates an elliptical structural model generated using OpenGoSim software, highlighting the facies groups within the reservoir formation. The reservoir is classified into four primary facies: ATK, TK, TN, and HPM, with their detailed characteristics summarized in Table 3. Among these facies, ATK and TK exhibit high permeability and are identified as the main production layers. The HPM facies, characterized by the lowest permeability, forms a single, but thick layer. It can be regarded as an effective sealing layer. The TN facies is marked by relatively low permeability, thin reservoir thickness, and multiple vertical distributions.

4.2. Reservoir model

The numerical simulation at reservoir scale employs assumptions consistent with the previously described box model. The simulation domain encompasses dimensions of 1.1 km in length, 1.05 km in width, and 879 m in thickness, discretized into a grid system of $50 \times 50 \times 28$

cells along the x, y, and z directions, respectively. The reservoir is characterized by no-flow boundary conditions at the top and lateral boundaries, while the bottom boundary maintains constant pressure due to aquifer support. One vertical well is considered in the simulations, with its location, depth, and perforation interval parameters taken from Ahuroa-2A.

The Ahuroa reservoir, which has transitioned from a production field to UGS facility, operates within a pressure range of 16–24 MPa. For simulation purposes, the initial reservoir pressure was set at 16 MPa. The gas–water contact depth was established at 2500 m at the initial state. The gas–water relative permeability relationships implemented in this study were identical to those utilized in the box model.

Based on well logging interpretation, the permeability values in the TN and HPM facies are relatively low compared with ATK and TK facies. In the Ahuroa field, ATK and TK facies are regarded as main production layers, while TN and HPM facies are regarded as interlayers and not perforated.

The scenario of the Ahuroa model is the same as that of the box model (Fig. 3). To investigate the influence of horizontal permeability anisotropy, three simulation cases were conducted under identical conditions with a fix $k_h/k_v=1$, while varying $k_{h,max}/k_{h,min}$ as 1, 5, and 10.

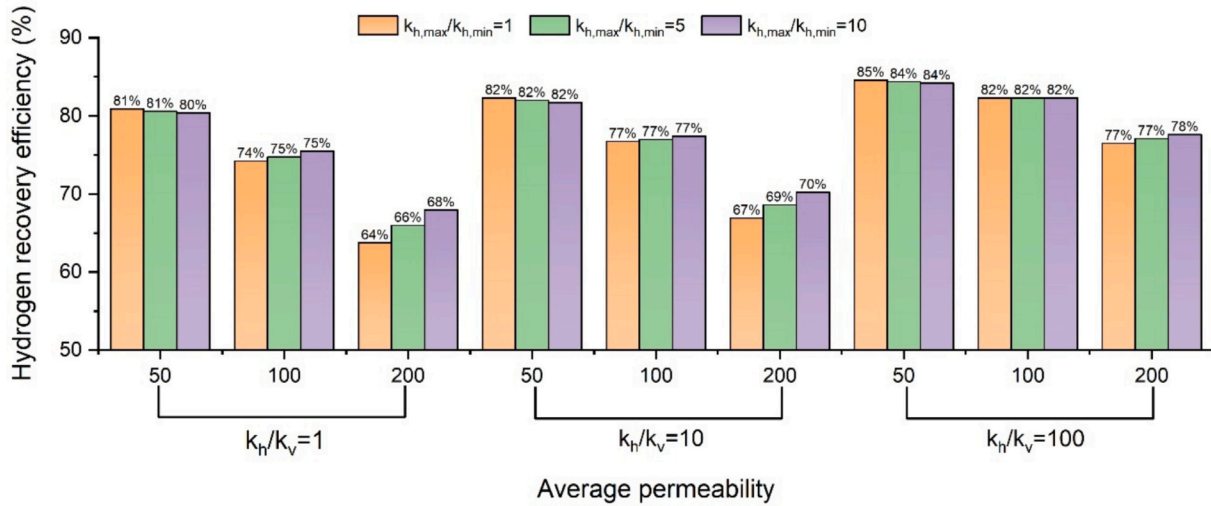


Fig. 12. Hydrogen recovery efficiency under varying average permeability and permeability anisotropy. The x-axis represents average permeability in the x-direction (50, 100, and 200 mD), grouped by horizontal-to-vertical permeability anisotropy ratios ($k_h/k_v = 1, 10$, and 100). Bar colours indicate different $k_{h,max}/k_{h,min}$ (orange: 1; green: 5 and purple: 10). The label above each bar indicates hydrogen recovery efficiency. A red label denotes scenarios where the operation could not be performed as designed.

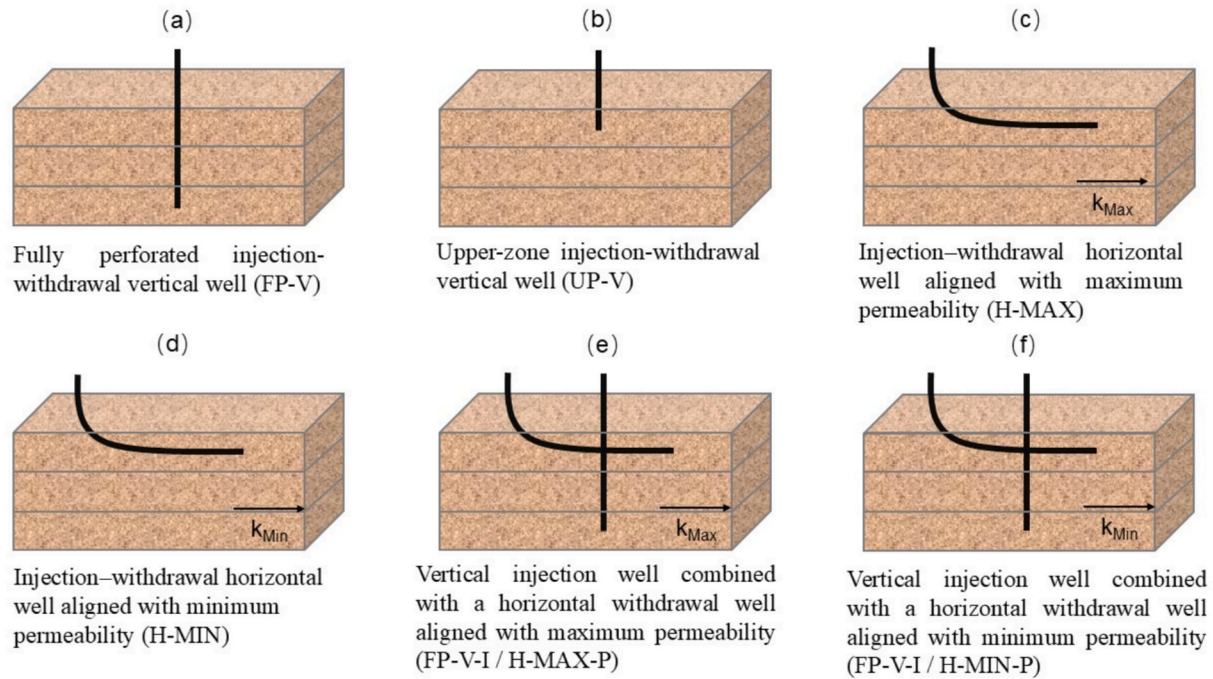


Fig. 13. Well configurations. (a) fully perforated injection-withdrawal vertical well; (b) upper-zone injection-withdrawal vertical well; (c) injection-withdrawal horizontal well aligned with maximum permeability; (d) injection-withdrawal horizontal well aligned with minimum permeability; (e) vertical injection well combined with a horizontal withdrawal well aligned with maximum permeability; (f) vertical injection well combined with a horizontal withdrawal well aligned with minimum permeability. K_{Max} and K_{Min} represent the maximum and minimum permeability directions.

A similar approach was used to evaluate k_h/k_v , where $k_{h,max}/k_{h,min}=1$ was fixed, and k_h/k_v was varied as 1, 5, 10 and 100.

4.3. Simulation results

4.3.1. Impact of horizontal-to-vertical permeability anisotropy ratio

The impact of k_h/k_v on hydrogen recovery efficiency is illustrated in Fig. 17. There is a positive correlation between permeability anisotropy and hydrogen recovery efficiency. As the anisotropy ratio increases from 1 to 100, hydrogen recovery efficiency increases from 76.8 % to 82.8 %, corresponding to an improvement of 6 percentage points. This

improvement can be attributed to the enhanced lateral spreading of hydrogen, which is further demonstrated by the hydrogen mole fraction distribution patterns shown in Fig. 18. Due to the presence of a thick, low-permeability HPM facies layer, the productive zones (ATK facies) were divided into two distinct zones. In the upper zone, the vertical interval between the producing layer and caprock is limited. $k_{h,max}/k_{h,min}$ shows minimal impact on flow behaviour, except when it reaches 100, at which point lateral spreading of hydrogen becomes pronounced. Conversely, in the lower zone, the absence of a distinct shale seal between the HPM facies and the reservoir base enables downward hydrogen migration. When the permeability anisotropy ratio is 1,

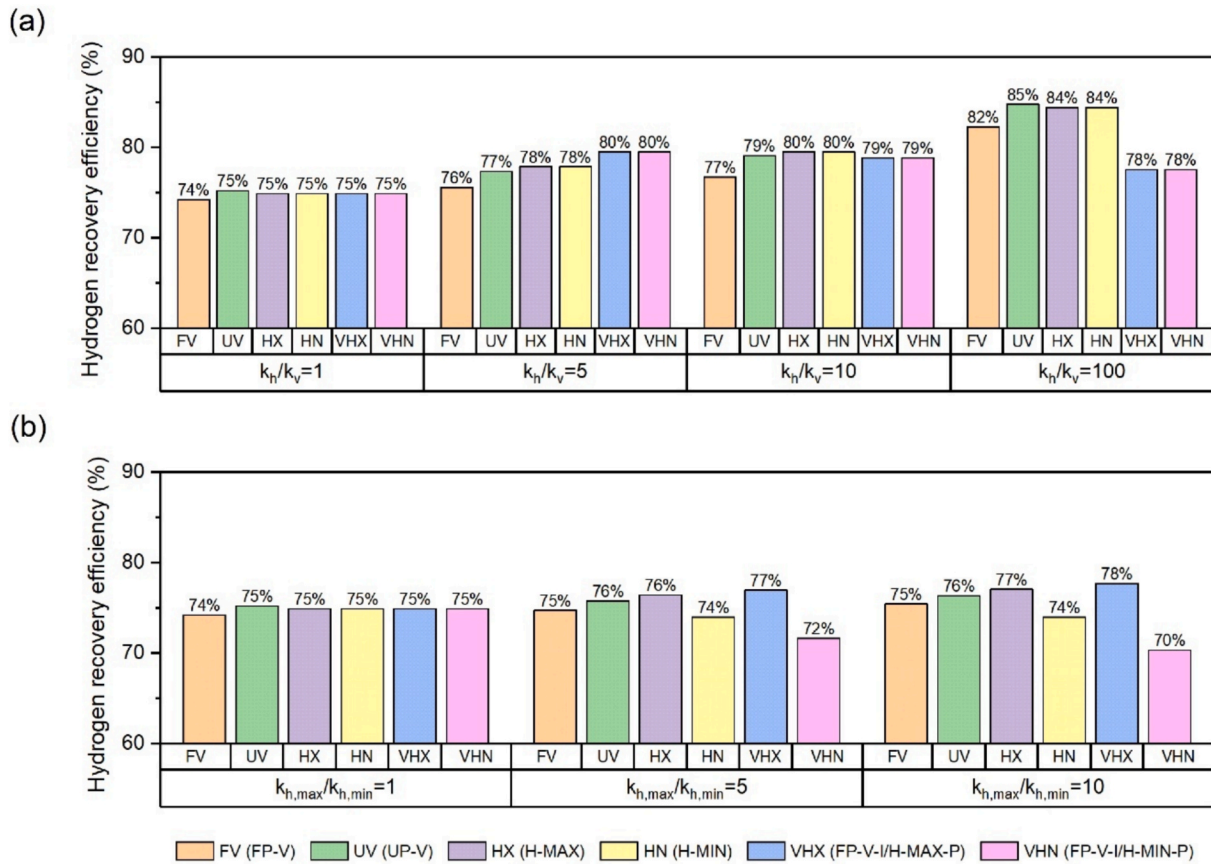


Fig. 14. Hydrogen recovery efficiency under different well configurations and permeability anisotropy conditions: (a) hydrogen recovery efficiency under varying horizontal-to-vertical permeability anisotropy ratios ($k_h/k_v = 1, 5, 10$, and 100) for six well configurations; (b) hydrogen recovery efficiency under varying horizontal permeability anisotropy ratios ($k_{h,max}/k_{h,min} = 1, 5$, and 10) for six well configurations.

hydrogen tends to flow vertically toward the base of the reservoir. However, as the k_h/k_v ratio increases, vertical migration is suppressed, and lateral flow becomes more dominant.

4.3.2. Impact of horizontal permeability anisotropy ratio

Fig. 19 illustrates the final hydrogen recovery efficiency under varying $k_{h,max}/k_{h,min}$. As anisotropy ratio increases from 1 to 10, the hydrogen recovery efficiency at the end of the simulation increases from 76.8 % to 77.3 %. On the other hand, a comparison mode was conducted in which the permeability of the ATK facies was set to its maximum value. Hydrogen recovery efficiency increases with increasing $k_{h,max}/k_{h,min}$. Moreover, the extent of this increase becomes more pronounced at higher average permeabilities. This trend is consistent with the results from the box model.

4.3.3. Impact of lithology on hydrogen recovery efficiency

k_h/k_v should be evaluated not only based on properties within a single layer, but also from the perspective of the entire reservoir. Even though the primary production layers are isotropic, adjacent low-permeability interlayer can reduce vertical permeability seriously. From the view of whole reservoir, it is anisotropic. In the following study, permeability values of TN facies were set to 0.1, 0.5, 1, and 10 mD, covering the range of TN facies permeability (Table 3). The average horizontal and vertical permeabilities of the reservoir were calculated using the arithmetic mean and harmonic mean methods [26]. With the horizontal permeability of other layers remaining constant, the horizontal-to-vertical permeability ratio (k_h/k_v) are 167, 34.1, 27.4, and 2.6. Simulation results are shown in Fig. 20. When the permeability of TN facies increases from 0.1 to 10 mD, the hydrogen recovery efficiency

decreases from 79.3 % to 75.2 %.

5. Discussion

Previous studies have investigated the impact of permeability anisotropy on hydrogen recovery efficiency [46,47]. However, their focus was limited to k_h/k_v , while the influence of $k_{h,max}/k_{h,min}$ received little attention. In this study, the influence of $k_{h,max}/k_{h,min}$ on hydrogen recovery efficiency is studied. Furthermore, rather than treating permeability anisotropy ($k_{h,max}/k_{h,min}$ and k_h/k_v) as an isolated parameter, this work also investigates its influence under varying reservoir thicknesses, average permeability values, and well configurations.

5.1. Permeability anisotropy and its implication for site evaluation in UHS

Hydrogen distribution in the reservoir is primarily governed by two mechanisms: gravity override and lateral flow [60], which together determine its spatial migration pattern.

Hydrogen density is lower than most possible cushion gas (e.g., natural gas, nitrogen, and carbon dioxide) [13]. Consequently, previous studies have mainly focused on vertical migration processes driven by hydrogen's low density, such as gravity override and k_h/k_v [44,47,61,62]. However, this study demonstrates that horizontal permeability anisotropy ($k_{h,max}/k_{h,min}$) also affects hydrogen recovery efficiency, particularly for well configurations with horizontal wells.

As shown in Eqs. (1) and (2), under identical gas properties and pressure difference, permeability anisotropy governs the flow velocity in different directions, while gas preferentially migrating along the

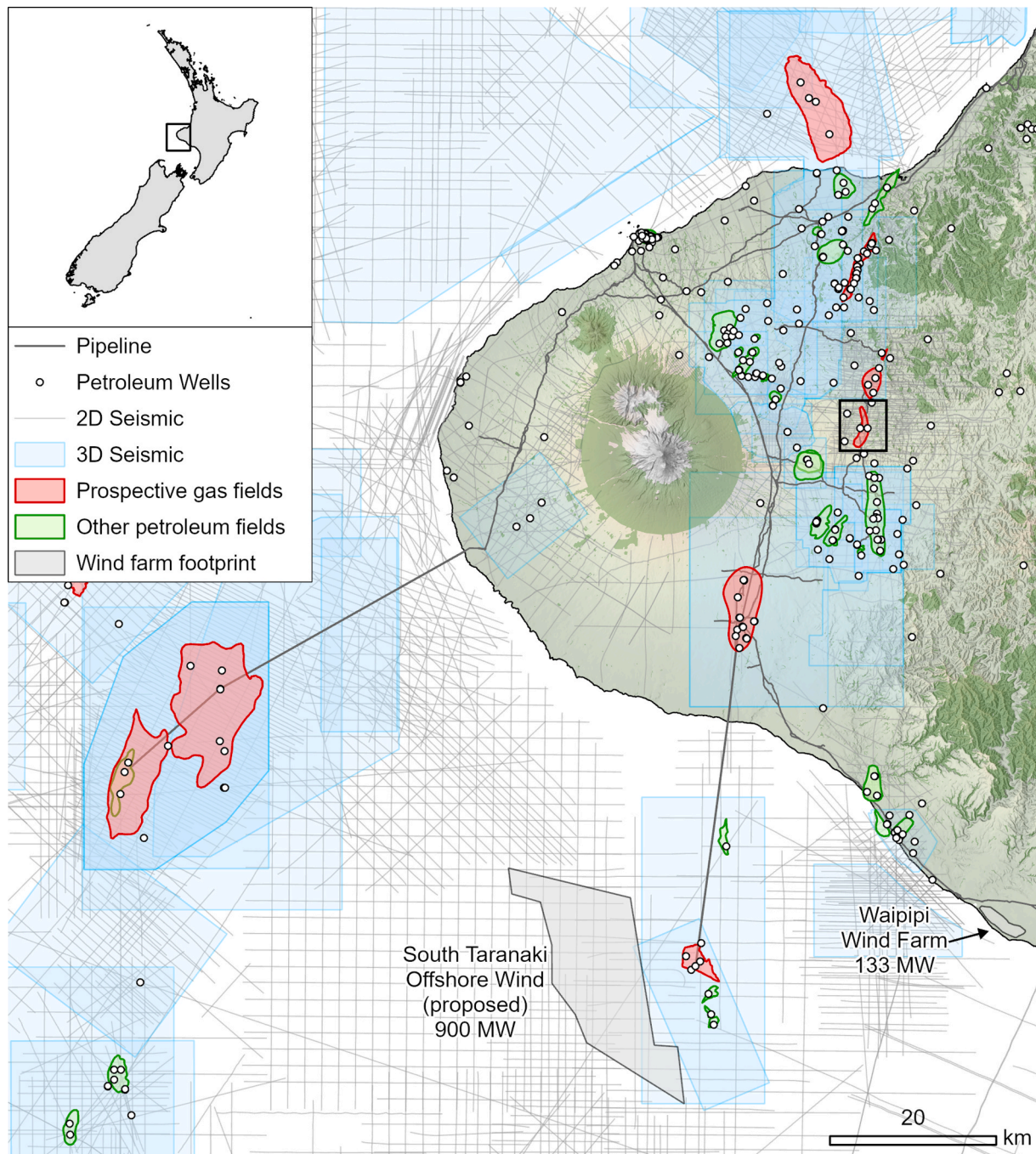


Fig. 15. Location map of Taranaki Oil & Gas province in New Zealand. The location of the Ahuroa field is indicated by the black box [55].

direction of higher permeability. When the average permeability is kept constant, $k_{h,min}$ represents the lowest permeability among the three principal directions. This restriction limits the lateral sweep of hydrogen in the horizontal plane and simultaneously suppresses gravity override, resulting in greater hydrogen accumulation in the lower part of the reservoir. As the average permeability increases, the absolute differences among directional permeabilities under anisotropic conditions also increase, thereby amplifying the influence of anisotropy on reservoir performance. As shown in Fig. 8, when $k_{h,max}/k_{h,min}$ increases from 1 to 10, the average hydrogen purity in each layer rises from 0.58 to 0.65. Since the total gas withdrawal rate among the layers differs only slightly, the increase in anisotropy mainly leads to a higher proportion of hydrogen in the produced gas, thereby increasing the hydrogen production rate.

For site assessment, thickness and average permeability are two important factors [58,59,63]. Some studies have demonstrated that reservoir thickness has a negative effect on hydrogen recovery efficiency, primarily because greater thickness enhances gravity override, leading to stronger gravitational segregation of hydrogen and reducing the overall recovery efficiency [58,64]. As discussed previously, a high $k_{h,max}/k_{h,min}$ ratio can restrict the influence of gravity override, thereby narrowing the difference in hydrogen recovery efficiency caused by reservoir thickness.

Average permeability plays a dual role in UHS. While high permeability facilitates gas flow within the reservoir, it also amplifies the adverse effects of viscous fingering and gravity override, thereby reducing hydrogen recovery efficiency [65]. Although high permeability can enhance withdrawal rate, but low hydrogen recovery

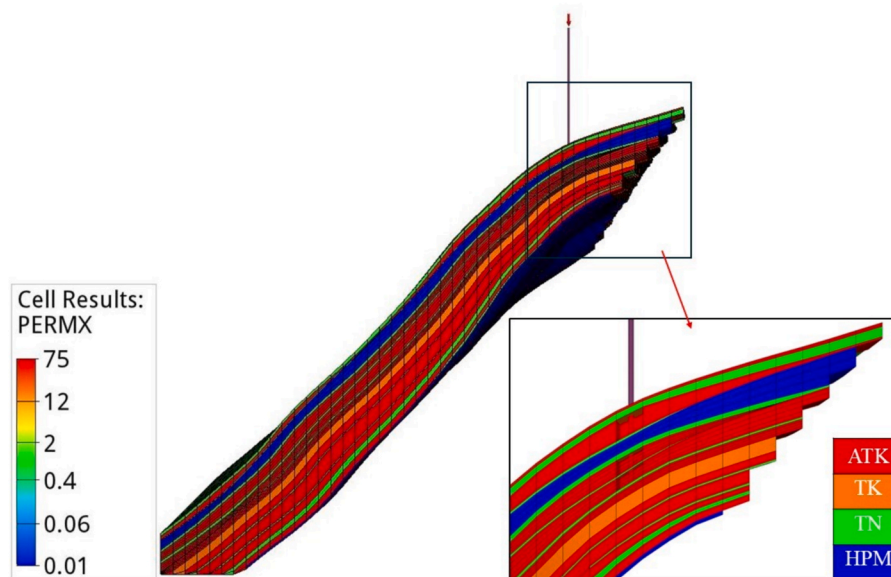


Fig. 16. Side view of the permeability distribution in the numerical simulation grid. The colour bar indicates reservoir permeability in the x-direction.

Table 3

Summary of petrophysical properties and sedimentary characteristics of the four reservoir facies.

Code	Dominant Lithology from logs	Average porosity (%)			Average permeability (mD)		
		Low	Median	High	Low	Median	High
ATK	Sandstone	14	16.5	17	25	75	150
TK	Sandstone with less Argillaceous and Mudstone/Siltstone	14	15.5	16	10	20	50
TN	Argillaceous and Mudstone/Siltstone, rate Sandstone	6	9	12	0.5	1	10
HPM	Mudstone/Siltstone		8		<0.01	0.01	0.5

efficiency will lead to additional costs for gas separation and treatment. In the site assessment, reservoir permeability should be considered in a comprehensive manner. Based on the findings of this study, the adverse effects associated with high average permeability can be mitigated by strong permeability anisotropy. Consequently, anisotropic reservoirs may offer improved hydrogen recovery performance in high-permeability formations.

Several studies have investigated strategies for optimizing well configurations to enhance hydrogen recovery efficiency [44,66]. However, these studies only consider isotropic reservoirs. The present study demonstrates that, in reservoirs with horizontal anisotropy, particular attention should be paid to the orientation of horizontal wellbores when designing well configurations. When the horizontal wellbore is aligned with the direction of maximum permeability, the horizontal minimum permeability results in reduced lateral sweep. Consequently, hydrogen tends to accumulate in the vertical direction, leading to increased hydrogen content in the lower part of the reservoir.

Permeability is typically measured through laboratory experiments on core samples [38,67]. However, when evaluating permeability anisotropy, laboratory data alone may not be sufficient due to scale limitations [68]. For example, natural fractures may not be observed in core samples due to limited scale, but their presence can influence fluid flow in the horizontal plane. Furthermore, permeability anisotropy is not only determined by rock properties within a single layer, but also by the interaction of multiple layers. For example, low-permeability mudstone layers can significantly restrict upward hydrogen migration, exerting an even greater effect than the maximum k_h/k_v anisotropy ratio assumed in this study. Therefore, the assessment of permeability anisotropy should not be limited to core-scale measurements or single layer, a reservoir-scale perspective is also essential to capture large-scale heterogeneities and flow-controlling features.

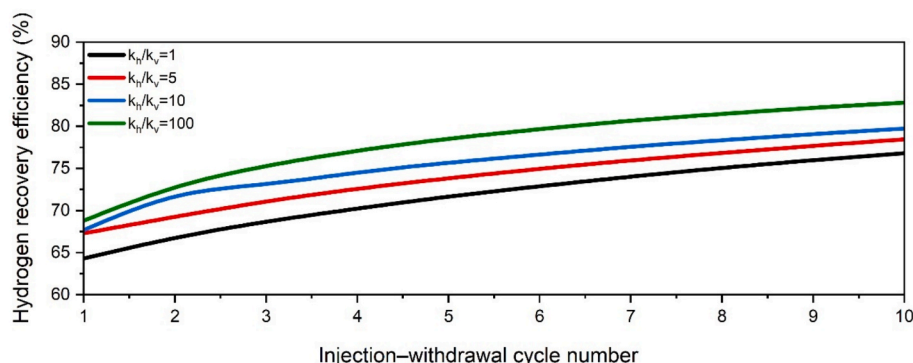


Fig. 17. Hydrogen recovery efficiency under varying horizontal-to-vertical permeability ratios (k_h/k_v): 1, 5, 10, and 100 represented by red, blue, green, yellow and black lines.

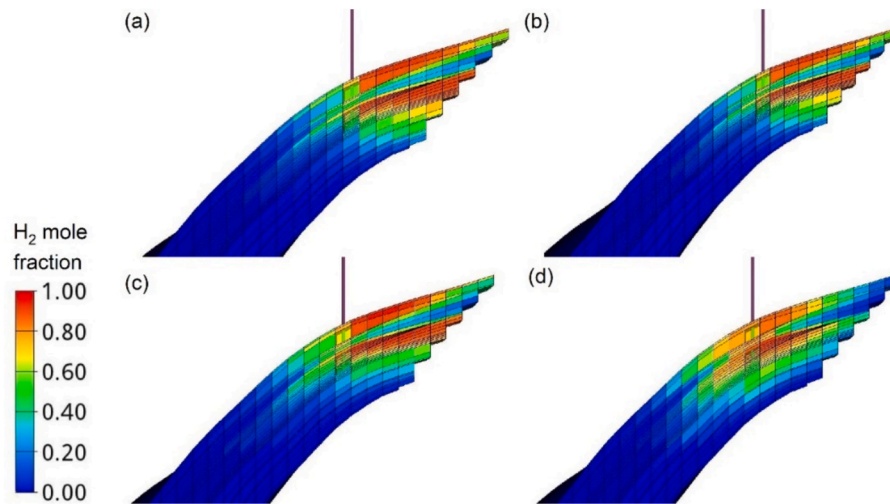


Fig. 18. Cross-sectional distribution of hydrogen mole fraction in the gas phase under varying horizontal-to-vertical permeability anisotropy ratios (k_h/k_v): (a) 1.0, (b) 5, (c) 10, (d) 100. The y-direction represents the lateral (left-right) dimension, while the x-direction indicates the front-back dimension in the model.

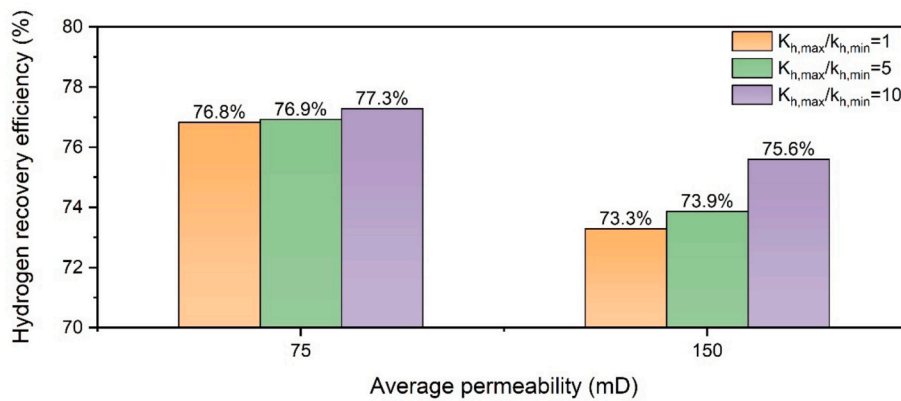


Fig. 19. Impact of horizontal permeability anisotropy on hydrogen recovery efficiency under varying average permeabilities.

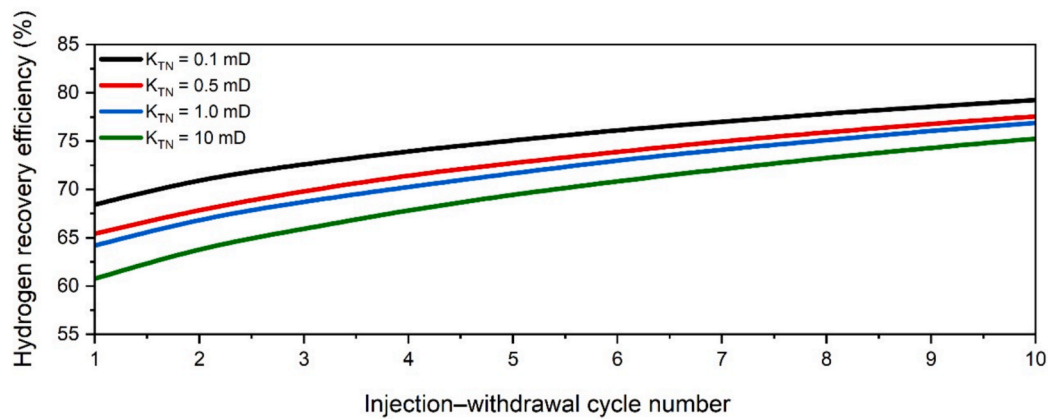


Fig. 20. Hydrogen recovery efficiency under varying permeabilities of TN facies (k_{TN}): 0.1, 0.5, 1, and 10 mD, represented by black, red, blue, and green lines.

5.2. Limitation and future study

In this study, the maximum reservoir permeability is assumed to be aligned with the x-direction and to be uniform across all layers. In reality, reservoir permeability typically varies between strata [62,69]. This discrepancy can affect hydrogen mobility at the layer scale and ultimately influence the hydrogen distribution within the reservoir. In

addition to absolute permeability, gas-liquid relative permeability curves also vary with lithological composition across different layers, which in turn affects gas flow and distribution within the reservoir [70]. To improve model accuracy, future work should take into account both absolute and relative permeability variations in different strata.

In addition to the anisotropy of formation permeability, recent studies have shown that relative permeability may also exhibit

directional dependence [71,72], which could further influence gas flow behaviour. Incorporating anisotropic relative permeability would provide a more realistic representation of gas flow. Future work should therefore consider the inclusion of anisotropic relative permeability to improve the accuracy of the simulation.

Chemical reactions are also considered a research hotspot in the context of UHS. Chemical reaction results mineral dissolution and precipitation, which will change the throat pore structure [73–75]. Fluids may even dissolve infillings within natural fractures, potentially increasing fracture apertures. Such changes, in combination with fracture orientation, can affect the directional flow capacity of gas within the reservoir. Future modeling efforts should integrate geochemical mechanisms to account for their impact on gas transport. Microbial interactions, such as methanation and sulfate-reducing reactions, may occur in subsurface environments and should also be considered [76–78]. Although they do not influence reservoir properties (e.g., porosity and permeability), they can reduce the underground hydrogen purity and thereby affect recovery efficiency. Therefore, to achieve more accurate reservoir evaluations, microbial reactions should also be taken into account in future studies.

This study primarily investigates the impact of permeability anisotropy on hydrogen recovery efficiency. However, it should be noted that permeability heterogeneity is also an important factor influencing gas migration, sweep efficiency, and ultimately recovery performance [79–81]. Several studies have demonstrated that heterogeneity can significantly alter hydrogen distribution and breakthrough behaviour. The present work does not account for spatial heterogeneity. Nevertheless, when the geological characteristics of a reservoir are well understood, heterogeneity should be incorporated into the modeling to make the evaluation of UHS site more accurate.

6. Conclusions

In this study, we investigated the influence of permeability anisotropy on hydrogen recovery efficiency during UHS using a box model. Then, our findings were validated with a realistic geological model based on the Ahuroa field. The following conclusion could be drawn:

- (1) Permeability anisotropy, including k_h/k_v and $k_{h,max}/k_{h,min}$, has an impact on hydrogen recovery efficiency. Compared with the isotropic case, when $k_{h,max}/k_{h,min}$ and k_h/k_v increase to 10 and

100, the final hydrogen recoveries increase by 1.3 % and 8.1 %, with all other parameters held constant.

- (2) Hydrogen recovery efficiency tends to decrease with increasing reservoir thickness under the same $k_{h,max}/k_{h,min}$ and k_h/k_v . While the magnitude of this reduction diminishes as anisotropy ratio increases.
- (3) Under constant k_h/k_v , as the average permeability rises, cases with larger $k_{h,max}/k_{h,min}$ exhibit increasingly higher hydrogen recovery efficiency than those with smaller ratios.
- (4) For well configurations with horizontal wells, horizontal permeability anisotropy should be taken into account, as it can lead to up to an 8 % difference in hydrogen recovery efficiency.
- (5) We validated the findings from the box model using a realistic geological model based on the Ahuroa gas field. The simulations demonstrate that the patterns observed in the box model also occur in the real-world geological model.

This study demonstrates that incorporating permeability anisotropy into reservoir modelling can improve the accuracy of site assessment for UHS. Ignoring this factor may result in incomplete analysis and potential misjudgement during site selection.

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CRediT authorship contribution statement

Jinjiang Liu: . **David Dempsey**: Writing – review & editing, Supervision, Project administration, Funding acquisition, Conceptualization. **Andy Nicol**: Supervision, Project administration, Funding acquisition. **Matt Parker**: Software, Resources, Data curation. **Karan Titus**: Writing – review & editing.

Declaration of competing interest

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

Appendix A

In the baseline model, the grid consists of $50 \times 50 \times 25$ blocks with a grid block size of $20m \times 20m \times 2m$. To test the model's grid sensitivity, a comparison model with a finer horizontal grid of $100 \times 100 \times 25$ blocks is built. Other parameters are consistent with the baseline model. Simulation results are shown in Fig. A1. The results demonstrate that the baseline model's calculations align with the fine-grid model within acceptable error margins. This confirms that our selected grid resolution effectively balances computational accuracy with resource utilization.

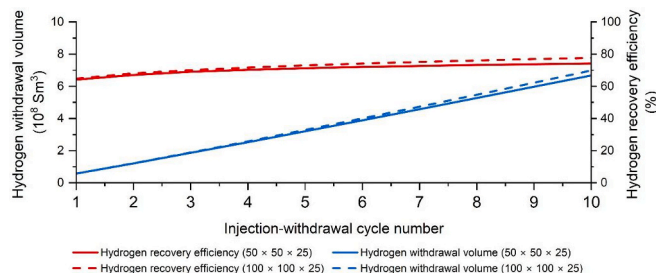


Fig. A1. Impact of grid resolution on hydrogen withdrawal rate and recovery efficiency (Solid line: baseline model; dashed line: comparison model with finer grid; red: hydrogen recovery efficiency; blue: hydrogen withdrawal volume).

Appendix B

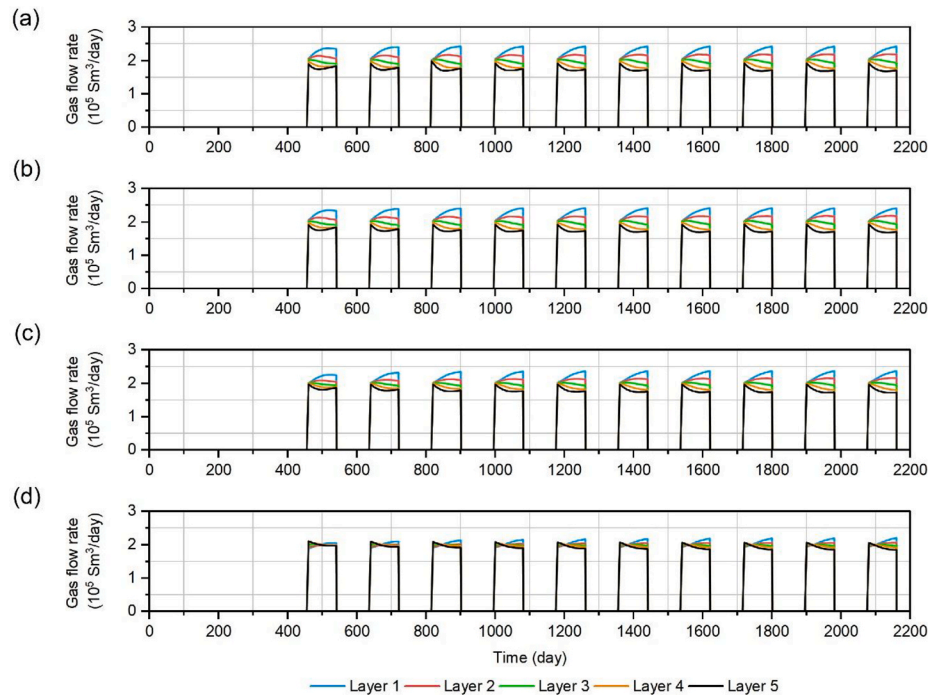


Fig. B1. Total gas flowrate across reservoir layers under varying horizontal-to-vertical permeability anisotropy ratios: (a) = 1, (b) = 5, (c) = 10, (d) = 100. Blue: Layer 1; Red: Layer 2; Green: Layer 3; Yellow: Layer 4; Brown: Layer 5.

See Fig. B1 illustrates total gas flow rate under varying k_h/k_v ratios at ambient temperature and pressure. When $k_h/k_v = 1$, gas flow rate decreases from Layer 1 to Layer 5. This is mainly because the hydrogen purity is higher in the top layer. According to Darcy's law, when other parameters remain constant, a lower gas viscosity leads to a higher flow rate. As the k_h/k_v ratio increases, the effect of gravity override diminishes, leading to a more uniform vertical distribution of hydrogen and more similar gas flow rates across layers.

Appendix C

See Fig. C1 illustrates bottomhole pressure over time under different well configurations when $k_h/k_v = 100$. The bottomhole pressure for the injection-withdrawal horizontal well ranges from 19.2 to 22.3 MPa. In comparison, the vertical well completed in the upper zone shows a wider pressure range, from 18.4 to 22.9 MPa. This indicates that the horizontal well can accommodate a greater injection/withdrawal rate.

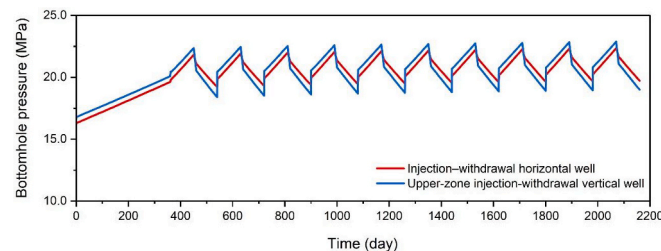


Fig. C1. Temporal evolution of bottomhole pressure under different well configurations at $k_h/k_v = 100$. The red line represents a horizontal injection-withdrawal well, while the blue line indicates a vertical injection-withdrawal well completed in the upper zone.

Data availability

Data will be made available on request.

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