Techno-economic analysis of developing an underground hydrogen storage facility in depleted gas field: A Dutch case study

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**Highlights**

- The Roden gas field is a potential case for seasonal and short-term H2 storage.
- A two-stage reciprocating compressor is required to inject H2 into the reservoir.
- Pressure Swing Adsorption unit is selected to separate H2 from gas impurities.
- The levelized cost of H2 storage for the base case is below 1 EUR/kg.
- Uncertainty analysis in different cost elements for the levelized cost is studied.

**Graphic Abstract**

**Abstract**

Underground hydrogen storage will be an essential part of the future hydrogen infrastructure to provide flexibility and security of supply. Storage in porous reservoirs should complement storage in salt caverns to be able to meet the projected high levels of required storage capacities. To assess its techno-economic feasibility, a case study of hydrogen storage in a depleted gas field in the Netherlands is developed. Subsurface modelling is performed and various surface facility design concepts are investigated to calculate the levelized cost of hydrogen storage (LCOHS). Our base case with hydrogen as cushion gas results in an LCOHS of 0.79 EUR/kg (range of 0.58–1.04 EUR/kg). Increasing the number of full-cycle equivalents from 1 to 6 lowers the storage cost to 0.25 EUR/kg. The investment...
Introduction

The Netherlands aims to reduce greenhouse gas emissions by 55% and 95% by 2030 and 2050, respectively, compared to 1990 levels to transition towards a carbon-neutral energy system. The Dutch government aims to reach 100% renewable energy supply in 2050 [1]. Wind and solar are expected to become the dominant sources of energy in the future system of the Netherlands, but they are weather dependent, i.e., they are intermittent energy sources. This requires flexibility in the energy system to deal with mismatch between supply and demand over short and long periods. An obvious candidate for providing flexibility in the energy system is energy storage, as it allows energy use to be shifted from periods of excess production to periods of deficit. Among existing methods, storage of energy in the form of hydrogen is gaining momentum worldwide because hydrogen is a green energy carrier that could be stored and transported. Hydrogen also has the potential to be used in power/heat (re)generation, transportation sector and as a feedstock in the chemical industry. Depending on the amount of hydrogen to be stored, the period over which to store it, and the intended end-use, one of the three methods below would be best suited [2,3].

- Gaseous state (compressed): above-ground (tank) storage for small-medium volume (daily storage) and underground for large volume (weekly-seasonal storage)
- Liquid state: liquid hydrogen for smaller volume and ammonia and LOHC\(^1\) for larger volume
- Solid state (material-based storage): storage by adsorption (on the surface of solids) and absorption method (within solids) for small volume (daily-weekly) storage

The combination of Pth\(^2\) and underground storage can be used to convert surplus electricity to hydrogen for later use to provide high charge and discharge capacity (GW scale) on inter-seasonal and seasonal timescales, providing a large-scale storage capacity (TWh).

In the current energy system, UGS\(^3\) provides flexibility at intra-to-inter-seasonal timescales and for security of supply. Natural gas has been stored in geological formations since 1915 and there are 662 UGS sites in the world as of 2020 [4]. Gas storage in depleted fields is by far the most common method for underground gas storage [4].

In the future energy system, hydrogen may ultimately replace natural gas to a large extent, and if so, UHS\(^4\) will play an important role. Hydrogen like natural gas can (potentially) be stored underground in depleted gas/oil fields, aquifers, salt- and lined rock caverns.

UHS in salt caverns has only been operated at four locations worldwide. There are three UHS sites in the US and one in the UK, all of which are for industrial feedstocks [5,6]. There are some pilot projects under development or in operation in the Netherlands [7], Germany [8], France [9] and the USA [10].

Experiences for injection of pure hydrogen in underground porous formations are limited. However, there have been some projects formerly executed for town gas storage (a mixture of hydrogen, carbon monoxide and methane) in aquifers in Germany [11], France [12], Czech Republic [13,14] and Poland [15]. Currently, all of them are closed or converted to UGS [15]. For hydrogen storage in depleted fields, there are only two pilot projects in Argentina [16] and Austria [17] where a mixture of hydrogen and natural gas was injected into the small reservoir. Although these pilot tests have proven that this technology works, an in-depth evaluation of pure hydrogen injection into porous reservoirs is still missing. There is no practical experience for UHS in aquifers.

Two other options for underground storage are aquifers and lined-rock caverns that can be used where there are no salt caverns and depleted fields [18]. There is no UHS pilot test in aquifers yet [19]. Though, the first pilot project of hydrogen storage in a lined-rock cavern is ongoing in Sweden [20]. Currently, they are also a small fraction of UGS sites that store natural gas in aquifers and lined-rock caverns [4].

UHS in single salt caverns has a storage capacity of between 100 and 250 GWh. The storage capacities required for hydrogen in the future energy system in 2050 could exceed that of what can be feasibly stored in clusters of salt caverns [21]. Therefore, depleted gas reservoirs with a TWh-scale hydrogen capacity are potentially attractive solutions for UHS.

A recent study in 21 countries in Europe [22] shows that to match expected supply with demand, 70 TWh of hydrogen storage capacity is required by 2030 and 450 TWh by 2050. The current capacity for re-using existing salt caverns is only around 50 TWh which is not equally distributed across Europe. This highlights that depleted gas fields may play a crucial role in the future hydrogen economy. Also, they are more widely spread across the globe and existence of the previous infrastructure favours their use for UHS in the future.

Several studies have reported on the technical challenges for UHS in reservoirs, including de-risking bio- and geochemical reactions [23–25], the interaction of hydrogen with rock, fluids, brine and microbe [26–28], hydrogen loss by dissolution, diffusion, dispersion and trapping [29,30].

Other important items to be investigated for future UHS sites are surface facility design and cost analysis of the

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\(^{1}\) liquid organic hydrogen carriers.

\(^{2}\) power-to-hydrogen.

\(^{3}\) underground gas storage.

\(^{4}\) underground hydrogen storage.
system. The special design requirements of surface facilities for expected injection and withdrawal rates and volumes of hydrogen have not yet received sufficient attention in the literature. There are some studies on the cost of storage carried out by Lord, Kobos and Borns [36] annumerical modelling of hydrogen flow behaviour [31,32] and impact of hydrogen exposure and cycling on geomechanical properties of reservoir rocks, caprocks and wells and implications for integrity [33–35] of the company DNV.GL [37]. However, a detailed analysis of the items included in the cost analysis, and the associated uncertainties, is often not reported. More detailed techno-economic assessments are needed to understand the impact of sensitivities in design and cost assumptions and identify knowledge gaps. This indicates the need to establish and include a surface facility design that fits with the subsurface characteristics and the energy system services to be delivered by the UHS. Therefore, the goal of this paper is to provide basic design concepts for a UHS based on a depleted gas field. The “Roden” gas field in the Netherlands was chosen as a case study. The techno-economic assessment of subsurface components and surface facility design allows to calculate the LCOHS.5

This study focuses on performing a cost analysis of a (notional) hydrogen storage facility that utilizes a depleted gas field in the Netherlands (the Roden gas field) for storage. The analysis includes an assessment of the Roden reservoir performance and explores design concepts for surface facilities (compressor and gas cleaning unit) to provide insights into uncertainty in cost estimates and the sensitivity of design on the LCOHS (Fig. 1).

Methodology

To come to the design of the hydrogen storage facility, the below step-wise approach is following.

1. Selection of the case study site in the Netherlands;
2. Subsurface modelling of reservoir performance to determine the storage capacity, injection and withdrawal rate for the scenarios, i.e., seasonal storage and short(er)-term storage with hydrogen or nitrogen as a cushion gas;
3. Surface facility design for both injection and withdrawal operations;
4. The LCOHS (the average net present cost of hydrogen storage facility over its lifetime) estimation and uncertainty analysis of influential parameters.

Fig. 2 displays the step-by-step approach of the technical analysis (subsurface and surface). After the design of the compositional (reservoir) model and scenario definition, the reservoir model is run to determine the storage capacity, well injection and withdrawal rate, injection pressure and composition of the gas mixture that is withdrawn from the reservoir. These outputs are used to design and scale the surface facilities (compressor and gas cleaning unit).

Case study

The Roden gas field, selected as a case study for the evaluation of a notional UHS site, is located in the north-eastern part of the Netherlands. This field is selected because of its favourable characteristics.

- The Roden field consists of thick sandstone with good permeability belonging Rotliegend Formation and is

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5 levelized cost of hydrogen storage.
considered a good candidate for underground storage in the Netherlands [38];

- There is public data available for the generation of a geological and dynamic model;
- The working volume of the field is around 1 bcm. This volume allows to classify this reservoir as small-medium size storage compared to larger reservoirs (e.g. UGS site in Bergermeer: 9.1 bcm) [38];
- The Roden field is located in the Groningen area, where many green hydrogen projects are ongoing and the first UHS pilot project is being carried out in a salt cavity [7]. Also, it is ideally located close to the planned hydrogen backbone network in the Netherlands.

The field has two wells that were drilled in the 1970s [39]. The field consists of two fault blocks with major bounding faults. Gas production from the field began in 1976. The initial composition of natural gas is mostly methane (81%) with a small percentage of ethane (4%), nitrogen (11%), CO2 (1%) and heavier hydrocarbons (3%). Both wells suffered severe water production, which led to the cessation of production in 2003. The initial reservoir pressure was 345 bar and the final abandonment pressure in 2003 was 106 bar [39].

Subsurface

Following the selection of the Roden gas field, the numerical simulation is performed to determine the total hydrogen storage capacity of the reservoir for seasonal and short-term storage. The total storage capacity is divided into cushion gas and working gas. The cushion gas is the gas volume that remains in the reservoir to maintain sufficient pressure and deliverability rates during the withdrawal time. The working gas is the volume that is injected and withdrawn during cyclic storage and is available for the market. The geological (static) model and black-oil model have been built before in Petrel software [39]. In the black oil model, the equations are solved based on the phases (oil, gas and water). In this study, the component concentration is required to determine hydrogen mixing with residual gases. Therefore, the equations should be solved based on the components using the fluid model analysis. Consequently, instead of the black-oil model, the compositional model (Eclipse 300) is developed and used in this study. The compositional model is validated with the GIIP,\(^6\) well rates and pressure reported in the black oil model.

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\(^6\) gas-initially-in-place.
The modelling runs are carried out considering the following steps.

1. Injection of cushion gas into the reservoir from abandonment pressure (106 bar) until the minimum working pressure;
2. Consecutive storage cycles consisting of periods of injection and withdrawal between minimum and maximum working pressures.

**Scenario definition**

The injection and withdrawal cycles are simulated for two scenarios: seasonal storage (one cycle per year) and peak-shaver (multiple cycles per year). For each withdrawal cycle, the working volume is calculated based on the well/wellbore constraints defined in Fig. 3, and the effect of the working reservoir pressure and the type of cushion gas on reservoir performance are monitored. For the base case of the simulations, a similar operational strategy to the two currently operational UGS of Norg and Grijpskerk in the Netherlands is used. These two UGS sites are located near the Roden field with similar reservoir properties and they are currently operating with WV/CV of 0.3 for seasonal natural gas storage. This fraction of working volume is also considered for the base case of UHS. Fig. 4 shows the seasonal behaviour of Norg field with a 6-months injection period (April–September) followed by a 5-months period of withdrawal (November–March). October is usually a month of soaking and/or maintenance.

**Surface design**

Based on the dynamic modelling results of the Roden field, the necessary compression power and scaling of the separation unit for purification are defined. The injection pressure and rate determined the required installed power capacity and number of stages, while the concentration of components of the gas withdrawn is used to design the separation unit to determine the type and amount of adsorbents in the unit.

**Economic analysis**

For each scenario, a LCOHS is calculated. The main elements considered for the cost analysis include cushion gas investment, compressor, wells/piping and gas separation unit. The LCOHS is an indicator for investment planning and is calculated as a ratio of the annual costs divided by total stored mass of working gas of hydrogen. Also, an uncertainty analysis is performed to determine the impact of each factor on the levelized cost.

**Results and discussions**

Besides the base case, influence of the several key parameters on the design of the hydrogen storage facility is investigated.

- Working pressure (3 scenarios)
- Type of cushion gas (3 scenarios)
- Number of cycles per year (2 scenarios)

In the following sections, the techno-economic analysis of these scenarios is discussed.
Subsurface modelling

Base case

The Base Case (case 1A) is designed based on a typical WV/CV ratio of 0.3 and maximum injection pressure of 251 bar with pure hydrogen as cushion gas. The calculated total storage capacity (WV + CV) is 3.3 bcm with the working pressure range of 185–251 bar. The required time to fill the reservoir until minimum working pressure (step 1) for the base case is 12 months. Depending on minimum and maximum working pressure, this time could be different for other cases (± a few months). In the base case, the plateau rate is 5.1 mln sm³/d for 5-month withdrawal (WV of 0.78 bcm or 2.3 TWh). The lowest hydrogen purity of the withdrawn mixture (calculated by numerical simulator Eclipse 300) is 96.7%. This indicates that pure injected hydrogen is mixed with the residual (unrecovered) gas in the reservoir, in particular methane, nitrogen and CO₂. In this study, the geo- and bio-chemical reactions are not considered in the subsurface modelling.

Effect of working pressure

The choice for different ranges of maximum and minimum working pressures is made to investigate its effects on hydrogen purity and WV/CV ratio [40]. Table 1 shows the results of three cases called high case (1B), mid case (1C) and low case (1D) with their corresponding storage capacity, maximum withdrawal rate and (lowest) purity of the withdrawn hydrogen. The results show a total storage volume of 4.1 and 2.8 bcm, for the high and low cases is directly proportional to the maximum working pressure of 270 and 234 bar, respectively. However, despite the lower volume and lower hydrogen purity of the low scenario, the WV/CV ratio appears to be slightly higher. In the case of the high scenarios, the lower WV/CV can be mainly explained by the difference in compressibility factor of hydrogen and natural gas. Note that there is a residual (natural) gas in the reservoir with an average pressure of 106 bar. Injection of cushion gas (hydrogen in these cases) with a higher compressibility factor provides lower WV/CV ratios at higher pressure [40]. i.e. the lower efficiency of storage (case 1B vs. case 1D in Table 1). The constraints in Fig. 3 are not limiting factors in these simulations. Higher purity of hydrogen withdrawn in case 1B appears to correlate with the higher pressure ranges, suggesting that hydrogen mixes less with the residual natural gas in the reservoir at higher pressure [42].

Effect of type of cushion gas

In this section, the possibility of using nitrogen as a cushion gas is investigated. The main reasons to use nitrogen as a cushion gas, instead of hydrogen, are its availability, lower investment cost and less reactivity of nitrogen with hydrogen compared to other gases such as natural gas and CO₂ [43,44].

<table>
<thead>
<tr>
<th>Case</th>
<th>Min-Max working pressure range (bar)</th>
<th>Total storage capacity (bcm)</th>
<th>Max 5-month plateau withdrawal field rate (mln sm³/d)</th>
<th>WV (bcm)</th>
<th>WV (TWh)</th>
<th>WV/CV</th>
<th>Lowest H₂ purity of mixture withdrawn (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1B (High)</td>
<td>193–270</td>
<td>4.1</td>
<td>6.7</td>
<td>1.00</td>
<td>3.0</td>
<td>0.33</td>
<td>95.8</td>
</tr>
<tr>
<td>1C (Mid)</td>
<td>177–251</td>
<td>3.3</td>
<td>6.0</td>
<td>0.91</td>
<td>2.7</td>
<td>0.38</td>
<td>95.6</td>
</tr>
<tr>
<td>1D (Low)</td>
<td>163–234</td>
<td>2.8</td>
<td>5.1</td>
<td>0.78</td>
<td>2.3</td>
<td>0.39</td>
<td>94.3</td>
</tr>
</tbody>
</table>
Nitrogen could also work as a barrier between hydrogen and the residual natural gas limiting potential geo- or biochemical reactions in the reservoir.

Using the base case parameters (case 1A), three different compositions for cushion gas are considered.

- 2/3 vol. H₂ + 1/3 vol. N₂ (Case 1A1)
- 1/3 vol. H₂ + 2/3 vol. N₂ (Case 1A2)
- 100% vol. N₂ (Case 1A3)

The average H₂ purity of the withdrawn mixture from the Roden field (calculated by numerical simulator Eclipse 300) is depicted in Fig. 5 for three annual cycles for the base case (1A) and the three different types of cushion gas (1A1, 1A2 and 1A3) modelled. The change in purity shows that the mixing of cushion and working gases is significant. The results show that for those cases where the cushion gas contains more than 1/3 volume of H₂, the purity of the hydrogen withdrawn is in all cycles higher than ~90%. Conversely, for cushion gas with more than 2/3 volume of N₂, the hydrogen purity only increases to 75% after the 2nd withdrawal cycle. This can be explained by the fact that N₂ produced is being replaced by H₂ in each consecutive injection cycle. In the last cycle after three years, H₂ purity is higher than 80% in all cases.

Effect of number of cycles per year

Sijm et al. [45] showed that the traditional seasonal storage pattern that is known from UGS may not be applicable to UHS, and that shorter-term storage cycles may (also) be required to balance the intermittent production of hydrogen with variable demand of hydrogen. In order to evaluate the performance of the Roden field for shorter-term storage cycles, two cases are considered. Cases 2A and 2B have the same WV, CV and working gas pressure as case 1A (base case). However, the storage time in cases 2A and 2B is shorter which results in higher field withdrawal rate in each cycle. Therefore, additional wells drilling is needed in the field. Table 2 shows the pressure range, injection (withdrawal) rate and the number of additional wells for cases 2A and 2B.

**Surface facility design**

**Compressor design**

Reciprocating and centrifugal compressors are the most common types of compressors for gas storage projects considering the current technologies [46].

Based on the general rules, centrifugal compressors are used for high-rate and low-pressure ratios. Whereas, reciprocating compressors are suitable when lower rates and higher pressure ratios are needed [47]. In our design both rate and pressure ratio are high. Due to the low molecular weight of hydrogen, a reciprocating (positive displacement) compressor is a better choice than a centrifugal one in order to gain better efficiency [48]. Furthermore, they are more flexible in capacity and pressure range. The main concerns for reciprocating compressors are high maintenance requirements and full-capacity spare.

Based on the subsurface modelling, the injection well rate and pressure are used as input parameters to determine the design parameters for the reciprocating compressor. Hydrodynamic work of compressor can be written as [49].

\[ gH_{pol} = \frac{K_{pol}}{K - 1} zRT_{in} \left( \frac{P_{out}}{P_{in}} \right)^{\frac{K_{pol}}{K} - 1} \]  

Equation 1

\[ K = \frac{C_p}{C_v} \]  

Equation 2

where, \( m \): polytropic exponent, \( K \): isentropic exponent, \( \eta \): polytropic efficiency, \( C_p\): specific heat at constant pressure \( (J/(kg.K)) \), \( C_v\): specific heat at constant temperature \( (J/(kg.K)) \), \( z \):

**Table 2 – Short-term storage of UHS in the Roden gas field with more than one cycle per year.**

<table>
<thead>
<tr>
<th>Case</th>
<th>Min-Max working pressure range (bar)</th>
<th>Number of total wells</th>
<th>Total maximum injection rate (mln sm³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1A (one cycle per year)</td>
<td>185–251</td>
<td>2 (old) + 0 (new) = 2</td>
<td>4.25</td>
</tr>
<tr>
<td>2A (two cycles per year)</td>
<td>185–251</td>
<td>2 (old) + 1 (new) = 3</td>
<td>8.50</td>
</tr>
<tr>
<td>2B (six cycles per year)</td>
<td>185–251</td>
<td>2 (old) + 5 (new) = 7</td>
<td>25.50</td>
</tr>
</tbody>
</table>

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compressibility factor, \( R \): universal gas constant (J/k/mol), \( T_{in} \): suction temperature (K), \( P_{in} \): suction pressure (Pa) and \( P_{out} \): discharge pressure (Pa).

The compressor has to be driven by an electric motor. The size of the motor (MW) required to drive the designed compressor (the installed power) can be obtained by Ref. [49]:

\[
P_{tot} = \left( \phi m \cdot gH_{pol} \right) / C_{17} \left( h_{m} + h_{c} + h_{mec} \right)
\]

Equation 3

where, \( \phi_m \) is the mass flow rate (kg/s), \( \eta_{m}, \eta_{c}, \eta_{mec} \), and \( \eta_{pol} \) are efficiencies for compressors that can be gathered from the literature. \( \beta \) is the safety factor of 1.1 for large motors. Table 3 shows the design parameters for different scenarios of UHS. The suction pressure is assumed 40 bar and discharge pressure and injection rate are extracted from Subsurface modelling part.

**Separation unit**

There are three common methods of hydrogen purification: membrane, PSA and cryogenic distillation [50]. In the case of UHS, the appropriate option for gas cleaning depends on the composition of the gas mixture that is withdrawn from the reservoir, the withdrawal rate, the temperature and pressure of gas mixture and the requirements of end-users (e.g. purity). Currently, the cryogenic method is highly energy-intensive, costly and less common [51]. Also, the withdrawal rate in the Roden case study is in the order of million m\(^3\)/day, which cannot be achieved by the membrane technology [51,52]. Therefore, PSA is the logical choice in this study which has been used widely in the gas industry.

PSA is based on the adsorption of gases (adsorbates) to highly porous solids (adsorbents) in the form of a fixed bed. The mass transfer from gas to solid is controlled by equilibrium effects (the difference between the fluid concentration and solid loading) and kinetic effects (the difference in diffusion rates of gases).

Activated carbon (AC) and zeolite (ZE) are the most dominant adsorbents [53] for hydrogen purification because AC can separate organic compounds and CO\(_2\) and ZE is able to remove N\(_2\) from the gas mixture. The rate of the adsorption for each component (pure gas) can be obtained by the Langmuir-Freundlich isotherm model [54]:

\[
q^* = q_{sat} b P / (1 + b P)
\]

Equation 4

where, \( q^* \): adsorbed phase equilibrium concentration of gas species (mol/kg), \( q_{sat} \): saturation limit of adsorbed phase concentration of gas species (mol/kg), \( b \): adsorption equilibrium constant (bar\(^{-1}\)) and \( P \): pressure (bar). To use the isotherm equation in different temperatures, the relation between \( b \) and temperature could be shown as follows [55]:

\[
b = b_0 \exp \left( -\Delta H / RT \right)
\]

Equation 5

where, \( b_0, \Delta H \) and \( T \) stand for pre-exponential factor (bar\(^{-1}\)), enthalpy change on adsorption (J/mole) and temperature (K), respectively. \( q_{sat}, b_0, \Delta H \) for AC and ZE are based on experimental data and reported in the literature [53].

Fig. 6 shows the amount of adsorbed gas vs. pressure for pure gases in AC and ZE. For both adsorbers, a low amount of
hydrogen is adsorbed. The combination of both adsorbers is suitable for adsorbing hydrocarbons, CO₂ and N₂. Therefore, the main parts of hydrocarbons and CO₂ are adsorbed in a bottom layer by AC and N₂ is mostly adsorbed by ZE in a top layer. Fig. 6 shows the separation of N₂ from H₂ is more challenging in comparison with methane, CO₂ and heavier hydrocarbons. Therefore, the recovery of separation is around 80% (range of 70%–90%) which should be considered in the design. While, 90% (range of 85%–95%) recovery is achievable for H₂-hydrocarbons mixtures [56].

After the selection of the adsorbents, the amount of adsorbents should be determined. Based on the mass balance between the feed and product (Fig. 7), the required mass of adsorbent can be calculated from the adsorbed species rate \( q^* \) and the change in the bed loading during the cycle:

\[
\tau_a = \frac{m_1}{m_2} \frac{m_{af}}{m_{bf}}
\]

Equation 6

where, \( F_1 \) and \( F_2 \) are feed and product flow rates (mol/s), \( y_1 \) and \( y_2 \) are feed and product mole fractions of the adsorbed component. \( \tau_a \) shows the time in which the bed is in the adsorption stage of the cycle(s). \( m_1 \) and \( m_2 \) stand for maximum and minimum adsorbent loading (mol/kg) which could be calculated from Fig. 6 \( m_a \) is mass of adsorbent per bed which is unknown. The fraction of the bed that is loaded at the end of adsorption phase of the cycle is shown with \( f_L \).

The separation process is continuous and the composition of the gas is changing over time during each cycle. Furthermore, the hydrogen has the minimum purity in the first cycle of the reservoir lifetime. Therefore the last time step of the first withdrawal cycle is the minimum purity level. To consider the conservative condition and to make sure that the unit design is working for all situations, this point is considered to design the separation unit. Table 4 shows the feed rate and composition for each scenario. To reach the purity level of 99.999% which is applicable for fuel cell and transportation, the amount of required activated carbon and zeolite are calculated using Equation (6). Considering the density of 550 and 620 kg/m³ for activated carbon and zeolite LiLSX, respectively, the total volume of the adsorbents is calculated. Applying bed voidage of around 35%, the volume of the vessel is determined. Based on the current technological level and maximum size of the vessel, the number of trains for the separation unit will be determined. The common number of vessels for a continuous operation is 4–12 [57].

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**Fig. 6** – The amount of adsorbed gas vs. pressure for pure gases in AC (left) and ZE (right).

**Fig. 7** – The schematic of a PSA vessel with feed rate and product rate of F1 and F2 using activated carbon and zeolite.
Table 4 — Feed (withdrawal) rate and composition of different cases and the amount of ZE and AC for production of pure H₂ in PSA unit.

<table>
<thead>
<tr>
<th>Case</th>
<th>Scenario</th>
<th>Feed rate (mln sm³/d)</th>
<th>Feed composition (%)</th>
<th>Required amount of AC, tonnes</th>
<th>Required amount of ZE, tonnes</th>
<th>Total vol. of adsorbents, m³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seasonal storage</td>
<td>Base case (1A)</td>
<td>5.1</td>
<td>96.674 0.366 2.700</td>
<td>0.567</td>
<td>48.7</td>
<td>23.6</td>
</tr>
<tr>
<td></td>
<td>High case (1B)</td>
<td>6.7</td>
<td>95.846 0.412 3.410</td>
<td>0.332</td>
<td>65.3</td>
<td>34.9</td>
</tr>
<tr>
<td></td>
<td>Mid case (1C)</td>
<td>6.0</td>
<td>95.639 0.480 3.541</td>
<td>0.341</td>
<td>58.6</td>
<td>31.5</td>
</tr>
<tr>
<td></td>
<td>Low case (1D)</td>
<td>5.1</td>
<td>94.335 0.623 4.599</td>
<td>0.442</td>
<td>51.7</td>
<td>27.0</td>
</tr>
<tr>
<td></td>
<td>2/3H₂ + 1/3 N₂ (1A1)</td>
<td>5.1</td>
<td>92.783 6.326 0.814</td>
<td>0.078</td>
<td>41.0</td>
<td>52.4</td>
</tr>
<tr>
<td></td>
<td>1/3H₂ + 2/3 N₂ (1A2)</td>
<td>5.1</td>
<td>74.269 24.842 0.720</td>
<td>0.069</td>
<td>36.9</td>
<td>112.0</td>
</tr>
<tr>
<td></td>
<td>100% N₂ (1A3)</td>
<td>5.1</td>
<td>29.004 70.085 0.831</td>
<td>0.080</td>
<td>30.7</td>
<td>147.1</td>
</tr>
<tr>
<td>Short-term storage</td>
<td>2A (two cycles per year)</td>
<td>8.5</td>
<td>91.754 0.907 6.695</td>
<td>0.644</td>
<td>95.2</td>
<td>45.1</td>
</tr>
<tr>
<td></td>
<td>2B (six cycles per year)</td>
<td>25.5</td>
<td>82.608 1.905 14.121</td>
<td>1.366</td>
<td>413.4</td>
<td>117.1</td>
</tr>
</tbody>
</table>

**Economic analysis**

The main components for LCOHS assessment include cushion gas, geological construction, wells and piping, compressors and gas separation unit. The levelized cost is calculated based on the CAPEX and OPEX of the system considering the interest rate and equipment lifetime. CAPEX is related to the investment period before the project stats (t = 0). This includes cushion gas investment and all surface facilities CAPEX. The calculated OPEX starts from the first day of operation of hydrogen storage site and includes well maintenance, compression and gas cleaning operational costs.

\[
\text{LCOHS}_{\text{total}} = \frac{(\text{CAPEX} \times \text{CRF} + \text{annual OPEX})}{m_{\text{H}}} \quad \text{Equation 7}
\]

where \(m_{\text{H}}\) is a total (stored) mass of hydrogen withdrawn from the reservoir over the lifetime of the facility which is available for the end-user. CRF stands for Capital Recovery Factor determining the present value of serial costs over a fixed amount of time (n) considering the interest rate (i) as follows:

\[
\text{CRF} = \left(1 + \frac{i}{1 + i}\right)^n - 1 \quad \text{Equation 8}
\]

\((n)\) is equipment (surface and subsurface) lifetime that facility can operate without any changes in main components. The equipment lifetime is considered between 15 and 25 years with a base case of 20 years [58,59]. (i) is the interest rate used to discount future cash flows to determine their present value. Based on the literature, 8% ± 4% is used for our analysis [59,60].

**Cushion gas costs**

\(H₂\) and \(N₂\) are used as cushion gas in this study. The CAPEX for cushion gas depends on the amount of gas and the price of \(N₂\) and \(H₂\). It is assumed that the source of hydrogen is blue hydrogen (hydrogen production using steam-methane-reforming method along with CCS) or green hydrogen (electrolysis of water using renewable electricity). \(N₂\) could also be produced using air separation methods. The amount of cushion gas is calculated based on the scenarios defined in Subsurface modelling part.

In this study, the hydrogen production cost is considered 1–4 €/kg with a base case of 2.5 €/kg [61–65]. The unit price of nitrogen production is assessed between 0.015 and 0.055 €/m³ [66], where the base case is set at 0.045 €/m³. Since cushion gas is assumed not to be consumed during the lifetime of the project (OPEX period), only CAPEX is calculated. It’s also assumed that the cushion gas stays in the reservoir and is not produced back at the end of the economic lifetime.

**Wells and piping costs**

Maintenance and operational expenditure for existing equipment (two current wells) are considered in the costs during the lifetime of the reservoir. Also for the cases requiring new wells, both CAPEX and OPEX are considered.

There are not many drilling experiences for underground hydrogen storage. Therefore, the data from onshore natural gas storage, geothermal or CCS projects could be used as a proxy for UHS. The analysis is performed in two categories: 1) re-used wells and 2) new wells.

The geothermal well costs in the US were studied by Lukawski et al. [67]. They calculated the relative probability of well costs in different depths in the US and developed a gamma distribution function to describe the total well costs:

\[
p(x_i) = \frac{\beta^\alpha}{\Gamma(\alpha)} (x_i - x_0)^{\alpha - 1} e^{-\beta(x_i - x_0)} \quad \text{Equation 9}
\]

\[
\Gamma(\alpha) = \int_0^\infty z^{\alpha - 1} e^{-z} dz \quad \text{Equation 10}
\]

where \(\alpha\) is the shape parameter, \(\beta\) is the rate parameter, \(x_i\) is the well cost in USD, \(x_0\) is the shift parameter and \(\Gamma\) is the gamma function. These constants are functions of depth and are given in the report [67]. This analysis is used as a proxy for UHS wells. The costs of a new well are assumed four times greater than re-used one [68]. The annual OPEX is considered 0.5 MEUR (range of 0.33–1 MEUR) [69,70].

For the piping inside the storage site, the capital cost per meter is calculated from this formulation [71]: \((L_0 = 100 \text{ km}, Q = 16000 \text{ tonne/day})\).

\[
\frac{e}{m} = (€600 / \text{m}) \times (Q/Q_0)^{0.48} \times (L/L_0)^{0.24} \quad \text{Equation 11}
\]

The CAPEX for a pipeline of 10 km is below 0.5 MEUR and
the OPEX is considered 4% of CAPEX and is not insignificant [71].

Compressor costs
In the literature, lots of equations exist for the cost estimation of compressors [72–78]. This leads to scattered data with a high range of prices. These formulations are a function of the compressor power. In some cases, the equation is based on the economics of scale when the cost of a similar compressor with a different size is known [76,77].

Due to the high uncertainty of compressor costs, the costs of compressors from two suppliers via private communication were used to find the most suitable estimation. Fig. 8 shows the cost of different equations over the range of compressor size along with supplier points for different cases. Most of the equations are over-estimated. Calado [78], Douglas [73] and Geitner [75] models are the most appropriate equations for compressor CAPEX calculation.

Compressor OPEX depends on the CAPEX and electricity costs. Therefore, both annual fixed operation and maintenance costs, as well as electricity costs, should be considered in the calculation [72):

$$OPEX = (A_0 \times H_{year} \times e \times DTE) + b \times CAPEX$$

where, $A_0$: Availability (85%), $H_{year}$: Hours per year (whole year = 8760h), $e$: the electricity costs (17–100 €/MWh with a base case of 60 €/MWh) [61,79–81], DTE: Driver Thermal Efficiency (90%), $b$: the constant for fixed OPEX (0.04).

PSA unit costs
The CAPEX of the PSA unit for the gas cleaning process is a function of sizing of pressure vessels, electrical system, column pipe and installation costs. The costs of adsorbents and maintenance are considered as an OPEX. The economic analysis of large-scale PSA is challenging as PSA is commonly used for small and medium scale of hydrogen purification in labs and refineries. There are some empirical equations for CAPEX estimation of PSA in the literature [82–86].

Similar to compressor costs, due to the wide range of CAPEX costs from the literature, a PSA supplier was requested to estimate the costs and then the most proper equation was selected. Among different equations, only Mivechian and Pakizeh [85] equation estimate the cost close to the supplier (Equation (13)). Other models’ estimations are below 10 MEUR which is too far below supplier estimates to be considered for this study. Such error shows that the costs could be a result of their small-scale PSA design. Therefore, the equation based on economics of scale (Mivechian and Pakizeh) is considered for PSA CAPEX.

$$CAPEX = C_{ref} \left( \frac{Q}{Q_{ref}} \right)^{0.66}$$

where, $Q_{ref} = 116 \text{ kmol/hr}$, $C_{ref} = 1.74 \text{ MEUR}$

Equation 13

Regarding OPEX, due to the multiple process and cycles of regeneration, the ability of adsorbents will decrease over time. Therefore, they should be replaced with a new one every 3–5 years and the OPEX analysis depends on adsorbent costs and replacements. An adsorbent provider estimated 1.5 €/kg for AC and 53.1 €/kg for ZE. Such a difference in AC and ZE adsorbent suggests that separating N₂ from H₂ is more expensive and consequently the OPEX is much higher.

Hydrogen recovery using the PSA method is around 80%–90% which means that at most 80%–90% of the stored volume could be used for the end-user. Consequently, this volume is used for the calculation of LCOHS. It should be noted that the separated gas stream will contain the rest of the components in the feed such as N₂, CO₂ and CH₄ and H₂ that could not be recovered. As this waste flow has a heating and economic value, a suitable strategy should be developed to make optimal use. For example, it could be used for heating in other parts of the installation or could be reinjected. Since this waste volume indicates loss of hydrogen (energy and revenue), further innovation should be guided to improve the efficiency of gas cleaning units in the future.

Levelized cost of hydrogen storage
Based on the input data from all components, the parameters for the calculation of LCOHS in the Roden field are listed in Table 5. For each parameter, the values including uncertainties and type of distribution function are shown. These
parameters include cushion gas investment, electricity price, compressor and well costs, recovery of PSA unit, interest rate and equipment lifetime.

The triangular distribution is selected for most variables as it is a continuous probability distribution which considers three values of minimum, most likely (mode) and maximum.

Using the “most likely” value as a base value for input parameters, CAPEX and OPEX and levelized cost of all components are estimated for different scenarios in Table 6 and LCOHS in €/kg, €/kWh and €/m³ are reported.

Table 6 shows that LCOHS for seasonal storage in the Roden field for the base case (case 1A) is 0.79 €/kg. The cushion gas, compressor and PSA account for 76%, 12% and 9% of the total levelized cost respectively, while wells and piping account for only 3%. Clearly, the largest cost component is the cushion gas. It is to be expected that the production cost of hydrogen will decrease significantly in the future and fall below 1 €/kg [67,87] and this will substantially lower the LCOHS. The levelized cost in terms of energy and volume are 2.36E-2 €/kWh and 6.73E-2 €/m³, respectively.

The results of cases 1B, 1C and 1D show that the range of working pressure significantly impacts LCOHS in the Roden field. The lower working pressure range (case 1D) lead to 22% reduction in LCOHS (0.61 €/kg).

Using nitrogen as a cushion gas has three main effects.

- Higher gas separation costs
- Lower recovery factor of PSA unit
- Lower costs for cushion gas

Fig. 9 depicts the LCOHS vs. hydrogen and nitrogen volume percentage as a cushion gas. Increasing the share of nitrogen could significantly reduce the levelized cost from 0.79 down to 0.50 €/kg (37% reduction). Also, using nitrogen or a nitrogen-hydrogen mixture as a cushion gas impacts the contribution of each component in the LCOHS. Fig. 9 also shows that when more nitrogen is used, the share of cushion gas is less dominant in the LCOHS. For cases with 100% nitrogen, the share of the cleaning unit and compressor (0.17 €/kg) is more than the cushion gas (0.14 €/kg).

### Table 5 – Uncertain parameters used for the calculation of LCOHS for the Roden gas field.

<table>
<thead>
<tr>
<th>Uncertain parameters</th>
<th>Distribution function</th>
<th>Minimum</th>
<th>Most likely</th>
<th>Maximum</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂ production cost (cushion gas investment), €/kg</td>
<td>Triangular</td>
<td>1.0</td>
<td>2.5</td>
<td>4.0</td>
<td>[61–65]</td>
</tr>
<tr>
<td>N₂ production cost (cushion gas investment), €/m³</td>
<td>Triangular</td>
<td>0.015</td>
<td>0.045</td>
<td>0.055</td>
<td>[66]</td>
</tr>
<tr>
<td>Electricity price, €/MWh</td>
<td>Triangular</td>
<td>17</td>
<td>60</td>
<td>100</td>
<td>[61,79–81]</td>
</tr>
<tr>
<td>Compressor CAPEX models</td>
<td>Triangular</td>
<td>Calado Douglas Geitner</td>
<td>73,75,78</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well CAPEX, MEUR</td>
<td>Gamma</td>
<td>6.1</td>
<td>6.9</td>
<td>7.7</td>
<td>[67]</td>
</tr>
<tr>
<td>The recovery of PSA unit in H₂-NG mixture</td>
<td>Triangular</td>
<td>0.85</td>
<td>0.90</td>
<td>0.95</td>
<td>[56]</td>
</tr>
<tr>
<td>The recovery of PSA unit in H₂–N₂ mixture</td>
<td>Triangular</td>
<td>0.70</td>
<td>0.80</td>
<td>0.90</td>
<td>[56]</td>
</tr>
<tr>
<td>Interest rate</td>
<td>Triangular</td>
<td>4%</td>
<td>8%</td>
<td>12%</td>
<td>[59,60]</td>
</tr>
<tr>
<td>Lifetime, year</td>
<td>Triangular</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>[58,59]</td>
</tr>
</tbody>
</table>

### Table 6 – CAPEX, OPEX and LCOHS in different scenarios of UHS in the Roden field.

<table>
<thead>
<tr>
<th>Cases</th>
<th>Seasonal storage — H₂ as a cushion gas</th>
<th>Seasonal storage — N₂ as a cushion gas</th>
<th>Short-term storage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1A</td>
<td>1B</td>
<td>1C</td>
</tr>
<tr>
<td>Number of cycles per year</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Annual amount of stored H₂, 1000 tonnes</td>
<td>59.1</td>
<td>75.6</td>
<td>68.6</td>
</tr>
<tr>
<td>CAPEX, M€</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cushion gas</td>
<td>346.6</td>
<td>469.9</td>
<td>318.9</td>
</tr>
<tr>
<td>Wells/piping</td>
<td>4.4</td>
<td>4.5</td>
<td>4.5</td>
</tr>
<tr>
<td>Compressor</td>
<td>12.4</td>
<td>16.0</td>
<td>14.1</td>
</tr>
<tr>
<td>Gas cleaning</td>
<td>30.8</td>
<td>36.8</td>
<td>34.2</td>
</tr>
<tr>
<td>OPEX, M€</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wells/piping</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Compressor</td>
<td>4.7</td>
<td>6.3</td>
<td>5.5</td>
</tr>
<tr>
<td>Gas cleaning</td>
<td>0.9</td>
<td>1.2</td>
<td>1.1</td>
</tr>
<tr>
<td>Total CAPEX, M€</td>
<td>393.4</td>
<td>526.4</td>
<td>370.9</td>
</tr>
<tr>
<td>Total OPEX, M€</td>
<td>6.6</td>
<td>8.5</td>
<td>7.5</td>
</tr>
<tr>
<td>LCOHS (€/kg)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cushion gas</td>
<td>0.60</td>
<td>0.64</td>
<td>0.48</td>
</tr>
<tr>
<td>Wells/piping</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
</tr>
<tr>
<td>Compressor</td>
<td>0.10</td>
<td>0.11</td>
<td>0.10</td>
</tr>
<tr>
<td>Gas cleaning</td>
<td>0.07</td>
<td>0.06</td>
<td>0.07</td>
</tr>
<tr>
<td>Total LCOHS (€/kg)</td>
<td>0.79</td>
<td>0.82</td>
<td>0.66</td>
</tr>
<tr>
<td>Total LCOHS (€/kWh)</td>
<td>2.36E-2</td>
<td>2.45E-2</td>
<td>1.97E-2</td>
</tr>
<tr>
<td>Total LCOHS (€/m³)</td>
<td>6.73E-2</td>
<td>7.01E-2</td>
<td>5.64E-2</td>
</tr>
</tbody>
</table>

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In the short-term storage, the number of cycles per year influences the LCOHS. In this condition, the cushion gas investment remains constant. However, the compressor, well and PSA costs are increased due to higher injection and production rates. Furthermore, more cycles increase the volume of hydrogen stored per year. The combination of these effects indicates that LCOHS is reduced with more cycles per year as would be expected (see Fig. 10). The power-law model matches with the data points suggesting this model is probably applicable for higher cycles in the Roden field.

Note that the level of hydrogen purity that is required at the surface in this study is assumed to be 99.999%; this purity level makes that suitable for all end-uses, including the transportation sector (fuel cell-grade). In case a lower purity level is sufficient the PSA unit might be down-sized or excluded from the surface facilities. For a purity level of 90%–95% which could be used for power and heat regeneration purposes [89], a PSA unit may not be needed. Our analysis shows that excluding a PSA unit could reduce the LCOHS up to 22%. For the PSA unit, besides CAPEX and OPEX, the recovery factor of hydrogen purification is an influential parameter in the economic analysis. A method or technology for gas cleaning with higher recovery than PSA could be a more attractive choice for UHS from an economic perspective. In

![Fig. 9](image-url) - The LCOHS in the Roden field vs N2 mole percentage as a cushion gas and the share of each component in these cases.

![Fig. 10](image-url) - LCOHS vs. number of cycles in cases 1A, 2A and 2B – The effect of short-term storage on LCOHS reduction.
any case, the need for gas cleaning and the technology to be applied should be decided based on the level of purity required by the end-uses.

To compare the results of our analysis with previous studies reported in the literature, Table 7 lists the LCOHS from two literature sources of UHS. DNV GL report [37] does not mention the detailed calculation of the levelized cost and predicts 0.3 €/kg for two cycles per year. In our study (case 2A), LCOHS with two cycles per year was estimated at 0.48 €/kg. The difference between the cost estimates could arise from the different assumptions in the two models. The LCOHS of Lord, Kobos and Borns [36] is higher than all cases in this study due to higher cushion gas cost, higher interest rate and higher compressor costs in their model.

In order to study the economical viability of UHS, we also compared LCOHS with the levelized cost of UGS in depleted gas reservoirs (see Table 7). The levelized cost of UGS in depleted gas reservoirs (for seasonal storage) found in literature falls in the range of 0.06–0.09 €/sm³ [90,91]. For a logical comparison, the costs should be compared in terms of energy deliverability. The levelized cost of UGS falls in the range of 0.005–0.008 €/kWh, which is three times lower than that of UHS (0.015–0.023 €/kWh). The difference is mainly due to lower cost of cushion gas (natural gas vs. hydrogen), compressors and gas cleaning units.

The electricity price range assumed in this analysis (17–100 €/MWh) is based on recent studies that investigated among others how different electrification scenarios for the Netherlands and the wider North Sea region would influence electricity prices [80,81]. It is worth noting that during the ongoing energy crisis, electricity prices have been considerably higher, and this would obviously increase the LCHOS calculated. To provide an insight into the sensitivity of the LCOHS to the electricity price, the base case (60€/MWh) has been run with higher electricity prices. Our results show that there is a linear relation between LCOHS and electricity prices. For every 50 €/MWh increase in electricity price, the LCOHS increases by 0.05–0.06 €/kg. For example, in case of an electricity price of 300 €/MWh, which regularly occurred in 2022, the LCOHS of the base case increases from 0.79 to 1.07 €/kg.

UHS is an appropriate method specifically for large volumes with a time domain of weekly to seasonal storage. In general, LCOHS for large-scale and long-term storage is lower than small volume and short-term storage [92,93]. However, in the future energy system, all types of energy storage will be needed based on the required capacity, duration of storage number of cycles and overall efficiency. Our study shows that UHS with LCOHS of below 1 EUR/kg is feasible. Levelized cost for above-ground (tank) storage will be in the same range but applicable for smaller volumes and daily storage [94]. LCOHS will be higher for other hydrogen storage methods (liquid state and solid state) [63].

Uncertainty analysis

An uncertainty analysis by Monte Carlo simulation is performed to improve the decision-making process under uncertainty (see Table 5 for input parameters). Due to significant uncertainty in some variables in the LCOHS calculation, instead of using a single average value for LCOHS, Monte Carlo simulation can be used to generate insights in a plausible range of LCOHS along with its confidence level.

This quantitative analysis uses a mathematical method to predict the range of possible outcomes with their probabilities. In this method, firstly the range of input data and their distribution function is determined. The distribution function is used to create a valid range of input variables regarding their probabilities (see Table 5). Afterwards, the random simulation is run for 10,000 times and the probability of the outcome is generated.

The uncertainty analysis is implemented for the base case (case 1A) and for the case where nitrogen is used as cushion gas (case 1A3). The results of others are similar to these cases because the equations in the LCOHS model are identical.

Base case. The simulation of Monte Carlo for 10,000 times in case 1A is illustrated in Fig. 11 (top). As most variables have a triangular distribution, the resulting LCOHS also follows triangular distribution. The analysis shows that the minimum, median (P50) and maximum LCOHS are 0.37 €/kg, 0.79 €/kg and 1.45 €/kg, respectively. Based on the data, P50 (0.79 €/kg) is the realistic value that has more chance of occurring. While P10 (0.58 €/kg) and P90 (1.04 €/kg) are the optimistic and pessimistic cases.

The results of Monte Carlo simulations could determine the effect of each variable in the final estimate of LCOHS. The relative importance of variables is depicted in Fig. 11 (bottom) by Tornado chart. The Tornado chart is useful for deterministic sensitivity analysis showing which variables are more important for decision-making to reduce the costs and/or uncertainties in the future. In case 1A, the cushion gas...

<table>
<thead>
<tr>
<th>Type</th>
<th>Reference</th>
<th>Levelized cost of storage</th>
<th>Considerations</th>
</tr>
</thead>
</table>
| UHS   | DNV GL company [37]              | 0.3 €/kg                  | • two cycles per year 
• Injection pressure of 250 bar 
• 2.8 TWh storage capacity 
• No detail information 
• Seasonal storage 
• Injection pressure of 137 bar 
• H2 production cost of 5 €/kg 
• No gas cleaning unit 
• Equipment lifetime of 30 years 
• WV/CV of 1 
• Interest rate of 10% 
• Seasonal storage |
| UHS   | Lord, Kobos and Borns [36]       | 1.04 €/kg                 |                                                                                   |
| UGS   | Rumbauskaitê and Zwart [90], Neumann and Zachmann [91] | 0.06–0.09 €/m³            |                                                                                   |
investment (hydrogen) is by far the most impactful variable to reduce LCOHS in the future e.g. by leveraging cheaper electricity and anticipating more efficient electrolyser operation. The interest rate is the second important variable which shows the role of the government and central bank to provide lower interest rates for accelerating the energy transition. The third parameter is surface equipment lifetime. Changing the lifetime from 20 years to 25/15 years results in ±5% change in the LCOHS. Two other important variables are electricity price and hydrogen recovery of PSA units. Cheaper electricity reduces the LCOHS mainly due to the reduction in OPEX costs of compression. Also, improving the separation technology for higher hydrogen recovery impacts the LCOHS. Other parameters do not influence the LCOHS significantly.

Nitrogen case. In case 1A3, the Monte Carlo simulation is performed for 10,000 times and the probability frequency and statistical data are represented in Fig. 12 (top). The results show that the LCOHS falls in the range of 0.33–0.68 €/kg. With a probability of 80%, the LCOHS varies between 0.42 €/kg (P10) and 0.56 €/kg (P90). The mean (0.49 €/kg) is close to mode (0.50 €/kg) indicating that most distributions are symmetric.

Conclusions

Underground hydrogen storage (UHS) in depleted gas fields will likely be necessary for the future energy system to balance the mismatch between energy supply and demand. Re-use of depleted hydrocarbon reservoirs to store hydrogen is an attractive solution because they can provide large storage capacities (TWh-scale) that far exceed the typical capacity of salt cavern clusters. In this paper, the Roden gas field is considered as a potential case for the design of a notional hydrogen storage facility in the Netherlands. Different scenarios are considered for the reservoir, with a base case working volume storage of 0.78 bcm (2.3 TWh). For each
scenario, a detailed cost analysis is carried out. The different individual components in the cost model are confirmed with the suppliers. Therefore, this study has added new and high granularity of insights on the cost levels and determines cost components of LCOHS for a large range of scenarios for the development of a UHS site.

Results from the numerical reservoir simulation for the Roden gas field confirm that it can potentially be used for hydrogen storage for both seasonal and short-term storage (i.e. assessed between 1 and 6 cycles per year). A two-stage reciprocating compressor (14.3 MW power and 4.25 mln Sm³/d injection rate for the base case) is required to deliver the required injection rates of hydrogen. PSA with zeolite and activated carbon as adsorbents is currently the preferred technology to separate the hydrogen from the gas impurities for this case study. Besides hydrogen, nitrogen can also be used as cushion gas, with some clear benefits and disadvantages. The use of nitrogen as a cushion gas will initially lead to a decrease in the purity of the hydrogen withdrawn. The purity increases progressively after successive cycles due to the replacement of the nitrogen by the newly injected hydrogen. Due to the tendency of adsorbents to separate organic compounds, the separation of nitrogen from hydrogen by PSA is more difficult than separation of natural gas from hydrogen leading to a lower hydrogen recovery (80% vs. 90%). Although the use of nitrogen lowers the cost of the cushion gas, it results in higher gas separation costs and a lower recovery factor in the PSA unit.

The net outcome for the LCOHS for the base case with hydrogen as cushion gas with 1 full cycle of injection and withdrawal per year is 0.79 €/kg. The investment cost for the cushion gas is the largest component in the LCOHS (76% of total levelized cost). Increasing the number of full cycle equivalents to six has a large impact and lowers the LCOHS down to 0.25 €/kg. When nitrogen is used as a cushion gas instead, the investment cost of cushion gas is significantly decreased and lowers the LCOHS to 0.25 €/kg. In this case, the cost contribution of compressor and PSA unit becomes higher than the cushion gas. The costs related to wells and piping are relatively minor (3%-5%) for both cases.

Fig. 12 – (Top) Probability frequency distribution of LCOHS with 10,000 random simulations in case 1A3 (nitrogen as cushion gas), (Bottom) corresponding tornado chart of LCOHS for case 1A3.

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Uncertainty analysis shows that the most dominant factors influencing the LCOHS are cushion gas investment, electricity costs, loss of hydrogen in the gas cleaning process, the interest rate and the equipment lifetime. Future business planning, design optimisation and innovations should focus on these five items to make underground hydrogen storage in depleted gas fields more cost-effective.

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**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.

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**Nomenclature**

**Acronyms**

| AC | Activated carbon |
| Bcm | Billion (standard) cubic meter |
| CAPEX | Capital Expenditure |
| CCS | Carbon, Capture & Storage |
| CV | Cushion (gas) volume |
| GIIP | Gas-initially-in-place |
| LCOHS | Levelized cost of hydrogen storage |
| LOHC | Liquid organic hydrogen carriers |
| MW | Megawatt |
| OPEX | Operational Expenditure |
| PSA | Pressure Swing Adsorption |
| PH2 | Power-to-hydrogen |
| TWh | Terawatt hours |
| UGS | Underground Gas Storage |
| UHS | Underground Hydrogen Storage |
| WV | Working (gas) volume |
| ZE | Zeolite |

**References**


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