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Market-based asset valuation of hydrogen geological storage

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HIGHLIGHTS

- Establish a Net Present Value (NPV) framework for evaluating geological hydrogen storage assets.
- Techno-economic analysis of hydrogen storage and renewable hydrogen production for peak power support.
- Comparison of single-cycle and multi-cycle storage scenarios for hydrogen geological storage.
- Insights into the impact of site development and well costs on project valuation.
- Application of the NPV framework for risk management and identification of key cost drivers.

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ABSTRACT

Because of hydrogen's low energy density, hydrogen storage is a critical component of the hydrogen economy, particularly when large-scale and flexible hydrogen utilization is required. There is a sense of urgency to develop hydrogen geological storage projects to support large-scale yet flexible hydrogen utilization. This study aims to answer questions not yet resolved in the research literature discussing the valuation of hydrogen geological storage options for commercial development. This study establishes a net present value (NPV) evaluation framework for geological hydrogen storage that integrates the updated techno-economic analysis and market-based operations. The capital asset pricing model (CAPM) and the related finance theories are applied to determine the risk-adjusted discount rate in building the NPV evaluation framework. The NPV framework has been applied to two geological hydrogen storage projects, a single-turn storage serving downstream transportation seasonal demand versus a multiturn storage as part of an integrated renewables-based hydrogen energy system providing peak electric load. From the NPV framework, both projects have positive NPVs, $46, 560, 632 and $12, 457, 546, respectively, and International Rate of Return (IRR) values, which are higher than the costs of capital. The NPV framework is also applied to the sensitivity analysis and shows that the hydrogen price spread between withdrawal and injection prices, site development, and well costs are the top three factors that impact both NPV and IRR the most for both projects. The established NPV framework can be used for project risk management by discovering the key cost drivers for the storage assets.

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Introduction

Background

In response to the need for energy transition and potential economic slowdown, the U.S. government recently introduced policies that accelerate the development of the hydrogen sector. Signed into law in August 2022, the Inflation Reduction Act included tax credits based on the emission intensity of hydrogen production, providing up to $3.00/kg for renewable hydrogen (with labor and wage criteria). In June of the same year, the U.S. Department of Energy (DOE) opened the application process for its $7 billion program to create regional hydrogen hubs (H2Hubs) nationwide; the 2021 Bipartisan Infrastructure Law funds the program. Clean hydrogen hubs will "create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store tremendous amounts of energy" [1]. The regional hub program expects to mobilize additional investments in the infrastructure pathway.

Geological storage of hydrogen has been recognized as critical to providing hydrogen as a cost-effective and reliable energy resources for various emerging market applications [2–4]. Several research studies focused on the requirements and valuation of hydrogen geological storage, pointing out the value proposition of geological storage for hydrogen [5,6] for providing cost-effective seasonal or longer-term storage as needed to respond to variations in supply and demand over aboveground storage options in terms of storage capacities, cost, and safety.

Current market challenges and recent policy directions create an urgent need for advancing geological storage projects that align with regional hub build-out, exposing knowledge gaps in the existing research literature for robust analysis and valuation on geological hydrogen storage directly for commercial project screening and development. First, an asset valuation framework for geological hydrogen storage is necessary for screening and developing commercially viable projects. Second, the valuation framework for hydrogen geological storage needs to integrate with clearly defined market assumptions to support plausible value chain build-out. This study builds an up-to-date NPV valuation framework for geological hydrogen storage that reflects current technology and market conditions and fits the purpose of asset screening and development activities.

Literature review

Given the low energy density of hydrogen, hydrogen storage is a critical component of building up a hydrogen sector in the energy system. Hydrogen storage options include compressed gas, liquid, or in combination with a metal hydride. Geological storage is considered a special case of compressed gas storage. Each alternative has its advantages and disadvantages. Geological (underground) storage[1] is the most inexpensive means for large quantities of hydrogen [2,4,7].

The traditional use of geological storage of hydrogen is to provide supply security for petrochemical sectors to avoid supply interruption and price risks. Furthermore, as many countries are considering electrification of their energy system with more renewables, hydrogen plays a valuable and specific role in this emerging system as the medium to integrate intermittent wind and solar power to meet the demand load.

Although a diverse set of options is available to provide backup power for modern grid with increasing share of renewables, it is long agreed that large-scale energy storage is required for the energy transition [3,8,9]. It is difficult to pin down the exact amount of storage required for the future system. Multiple studies for the projection of future energy storage demand in Germany concluded that despite the wide range of estimates, the long-term need is in the low-terawatt-hour(TWh)[2] range for an industrial country such as Germany with a population of 80 million [2]. A more recent study in 2021 by Gas Infrastructure Europe confirmed this perspective, and estimated about 111.4 TWh hydrogen storage need for Germany, of its estimated 470 TWh of demand for hydrogen by 2050. This study also estimates about 466 TWh of hydrogen storage need for Europe, about 23.7% of its forecasted demand, by 2050 [8]. A similar study has shown that Australia needs storage capacity, that is 30% of its yearly production of hydrogen including meeting its domestic demand and potential exports, around 172 TWh by 2050 [10,11]. It is demonstrated that hydrogen energy storage can be an effective solution for large-scale, long-term energy storage as we move towards a more sustainable energy system [10].

Fig. 1 provides an overview of the capacity and discharge time of various large-scale storage options. Discharge time is defined as the maximum duration of power production at maximum power output. This chart shows that only hydrogen and methane chemical storage can meet the terawatt-hour output [2]. This demonstrates that hydrogen energy storage can be an effective solution at scale compared to other current storage approaches for improving the electricity grid's resilience and reducing the need for fossil fuel–based power.

A comprehensive literature review of worldwide operating and potential storage sites confirms that geological structures have been successfully used to store hydrogen [12].

Detailed research case studies focus on identifying favorable geological structures and conditions for hydrogen geological storage in specific regions and countries, such as Romania [13], Spain [14], France [15], Germany [16], Poland [17–19], U.S. California [20], China [21], the United Kingdom [22,23], Canada [24], Australia [5,10], the Netherlands [25,26], Turkey [27,28], and India [29]. Options for geological storage for hydrogen include salt caverns, which have already been proven successful as working facilities, and depleted fields, which, while not yet operating as hydrogen storage, are attracting additional interest from researchers and industry.

Hydrogen geological storage has been a versatile solution for energy storage for several applications [2,3,30]. Hydrogen geological storage can be used as traditional storage for feedstock for hard-to-abate sectors, including petrochemical, refinery, steel making and cement [16,30] [–] [32]. It can also

[1] Geological underground storage is referred to as either geological storage or underground storage interchangeably in the literature.

[2] TWh: terawatt hour.

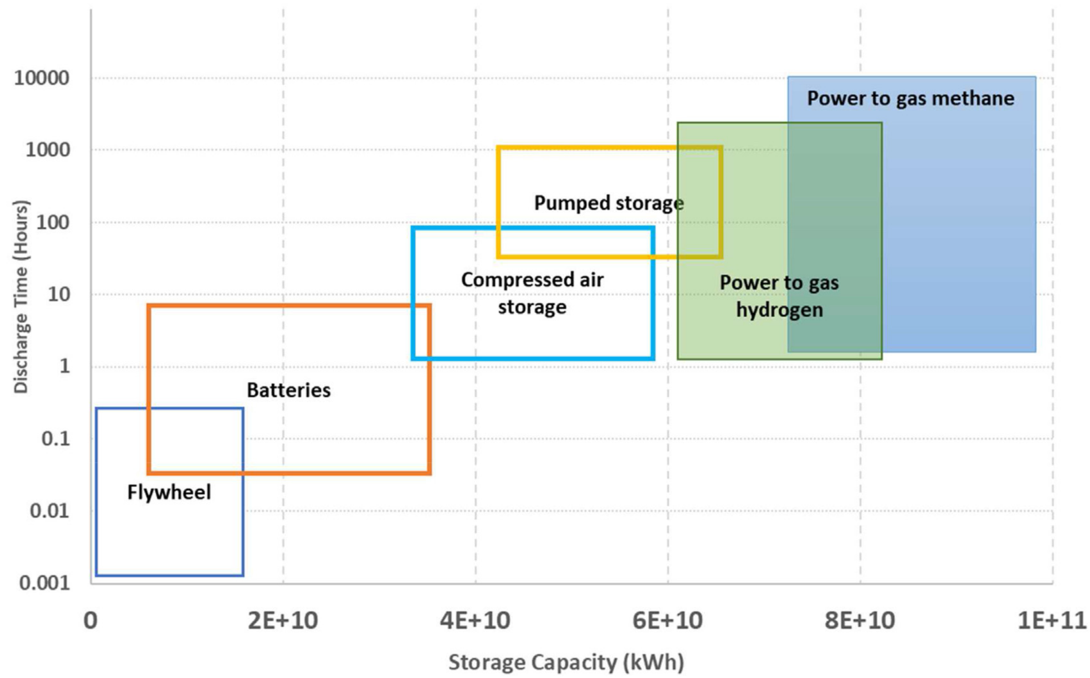

Fig. 1 – Discharge time vs. storage capacity for different storage techniques [5,12].

provide low-carbon backup energy in the form of electricity or fuel to supplement the electricity grid or gas distribution [3,21,33] [–] [36]. Furthermore, geological storage exhibits advantages over other storage options for hydrogen [6], as summarized below.

- Geological storage has security benefits, as the facilities are less likely to be affected by fire, harsh weather, and military or terrorist attacks.
- Geological hydrogen storage can provide a flexible range of potential storage capacities up to gigawatt scale and is considered the best option for large-scale and long-term storage, whereas tanks are considered the best option for short-term and small-scale storage [5,12,37–39].
- Geological hydrogen storage is considered a low-cost option compared to large-scale surface tanks.
- The existence of ample appropriate geological storage locations allows for decentralized storage.

Researchers have conducted studies on the feasibility of subsurface hydrogen storage [10,21,40] [–] [42]. Selecting a suitable storage site as the first step plays an important role, and many studies focus on the decision-making criteria for potential storage sites [18,43]. While geological structures and conditions serve as critical prerequisites for a successful hydrogen geological storage asset, cost analysis is an important aspect of large-scale geological storage for hydrogen, as the cost can vary greatly on the basis of site-specific geological parameters, surface conditions and required deliverability [7,44–47]. Lord et al. estimated the capacity requirement and development costs for hydrogen geological storage based on city population size for peak transportation demand to four major U.S. cities and provided an estimated range of cost per kilogram of hydrogen for the four types of geological options, covering salt caverns, depleted oil and gas reservoirs, aquifers, and mined hard rock caverns [47]. Taylor et al. divided the project's total cost into three parts—capital cost, operating cost, and additional investment. The capital cost includes the site preparation and development, equipment purchases, general working system (heating, lighting, and monitoring), well, and surface last-mile pipeline. The operating cost includes the water-cooling, power, and labor costs during the operation of the storage facility, and additional investment covers land cost [48], which is not a sunk cost to the project. The current study includes the cost of cushion gas as part of working capital, assuming that the cushion gas can be sold at the end of the project life. Furthermore, many of the studies include a storage asset not as a standalone facility, instead calculates the levelized cost of energy or electricity (LCOE) as part of an integrated energy system or the levelized cost of storage (LCOS) [5,14,25,26].

Rising investment momentum in the hydrogen value chain creates an urgent need to develop commercially viable hydrogen storage projects that fit the overall decarbonization pathway. The current study aims to bridge the insufficiency in the current literature by providing an up-to-date storage valuation framework that can directly support project screening and decision-making. First, the current study provides a detailed valuation of one single storage asset, including development and operation costs, based on a realistic simulation of the facility's downstream takeaway demand. Second, this study has two examples of salt cavern hydrogen storage with market-condition and utilization. Only the valuation of the hydrogen storage, not the entire energy system [49], is included in this research.

At last, this study recognizes possible uncertainties in evaluating storage projects. It conducts a sensitivity analysis

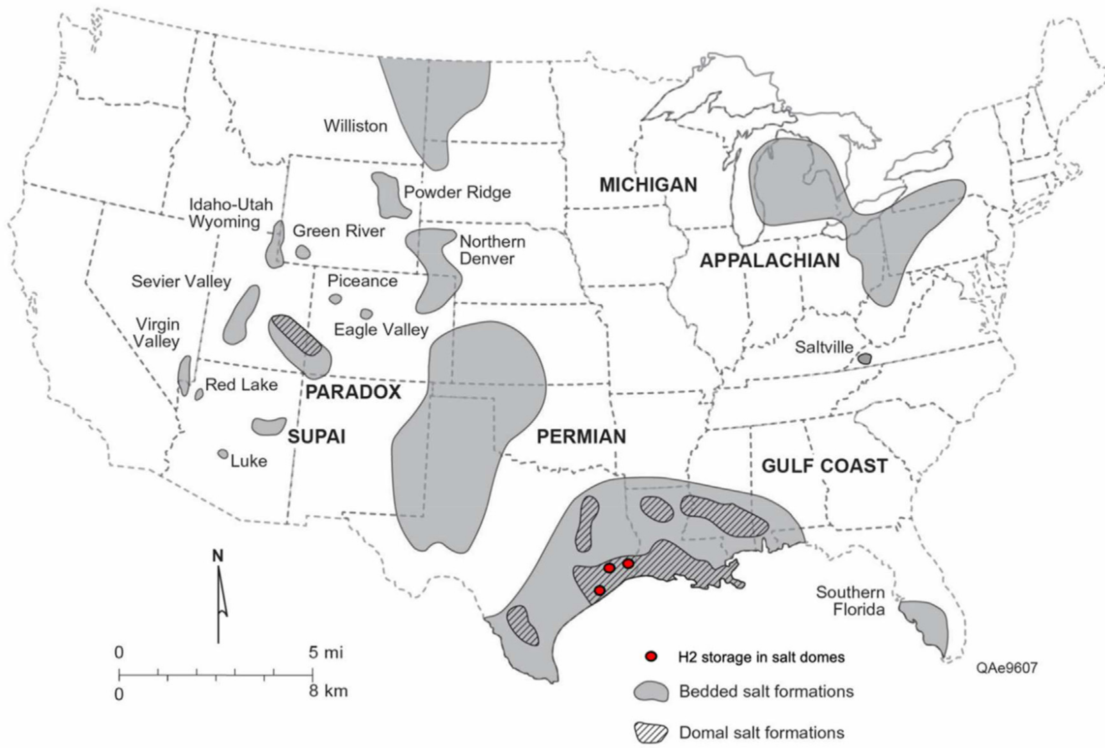

Fig. 2 — Geographic distribution of domal salt versus bedded salt formations in the United States [52].

of the project valuation to provide a better understanding of the key factors affecting revenue and costs for a storage facility. This is a critical tool in screening and developing a commercial project that provides a quantitative way to compare multiple factors consistently for developers at the early stages of the project. The results of the sensitivity analysis will also guide the project risk management with the identified key cost drivers. This study is not intended to cover all barriers and challenges to a successful geological storage project, which include geological and reservoir constraints, technical and safety limitations, legal barriers, conflicts of interest, and social acceptance of geological underground hydrogen storage [50,51].

Salt cavern storage potential in the United States

Salt caverns can be placed in two different types of geological salt formations, bedded salt formations and domal salt formations. Three hydrogen storage sites have been in operation in salt domes located on the Gulf Coast in Texas for decades; these facilities have been serving refineries and the petrochemical industry. A salt dome is a subsurface geological structure that forms when evaporitic minerals, mainly halite, intrude into younger sedimentary units, forming a domal structure that can be more than three miles high and more than two miles in diameter. In contrast, bedded salt formations cover more area (hundreds of thousands of square miles) but are usually less than 305 m (1000 ft) thick. Bedded salt formations are also more heterogeneous in terms of mineralogical content (and, therefore chemical composition). An average salt cavern in a salt dome can be 670 m high and 67 m wide (2000 ft by 200 ft); salt caverns on bedded salt formations are considerably smaller. Salt domes are geographically restricted to certain geographic areas in the United States (along the Gulf Coast region, offshore Gulf of Mexico, and some areas in Utah and Colorado), while bedded salt formations are more widespread (including the Permian Basin, Appalachia, the Williston Basin, and other smaller basins across the continental United States) (Fig. 2). Salt cavern construction and operation is not a new technology, but it has never been used at scale for hydrogen storage beyond current uses for the petrochemical industry and refineries. The upscaling of hydrogen storage in salt caverns for the purposes of energy storage and power generation will involve increasing the frequency of hydrogen injection and withdrawal cycles, requiring the implementation of new considerations that will need rigorous subsurface characterization, monitoring and innovative engineering to handle these operational conditions and challenges [52].

Methodology

Geological storage "synchronizes" supply and demand across time and locations in a cost-competitive way. This study presents two scenarios, scenario A and scenario B, for such synchronization, as shown in Fig. 3. In scenario A, geological storage receives sourcing gas from a ratable and responsive hydrogen supply, like a steam methane reforming (SMR) process with carbon capture and storage, for end markets like industry (chemical plants and refineries) and transportation. The value of storage is to have additional hydrogen to meet

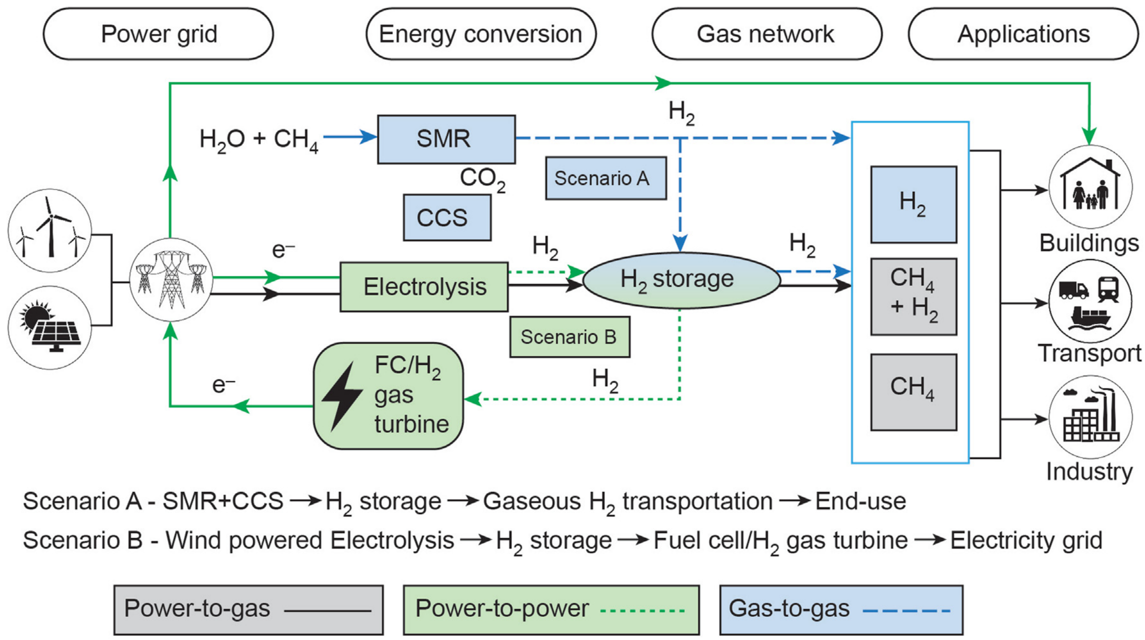

Fig. 3 — Market pathways with geological hydrogen storage (scenarios A and B).

the demand for various demand patterns (seasonality and weekends) or to serve as a supply backup for security reasons (in severe weather events with force majeure threats to regular suppliers). Scenario B considers geological storage collocated with renewable-based hydrogen production and takes advantage of hydrogen produced from intermittent renewable generation, converting it into a reliable storage inventory for peak market conditions.

Valuation framework

The stakeholders for a geological hydrogen storage asset include asset owners, value chain and market participants, and even communities near or served by the asset. Different stakeholders evaluate the same project with different yielding benefits and costs based on their perspectives and interactions with the asset. Three analytical components constitute the valuation framework in the current study and provide analytical reference to all three types of stakeholders.

- Techno-economic analysis (TEA) focuses on the capital cost components and operating cost assumptions for a stand-alone asset.
- A value chain scenario describes the operating schedule and requirements for the asset, including assumptions about the upstream pathway and pattern for injection and withdrawal requirements for the downstream user. This step describes the volume and utilization of the asset.
- The net present value (NPV) model combines the utilization, cost, price (market perspective), and finance theory to calculate the asset's cash flow throughout its lifetime, risk-adjusted discount rate, and estimate the assets' value and rate of return. The NPV model acts as the framework's last step, integrating the cost, economic, risks, and market perspectives into one value.

The TEA includes the geological and engineering parameters of asset design and cost assumptions of capital and plant-operating costs. The current research validates and reviews the technical assumptions of the techno-economic model in several ways. Many engineering parameters are determined by the market's requirements and the facility's downstream demand. Therefore, market-simulation scenarios are included in this research to provide a description of supply and demand and assumptions about the operating requirements of the facility. These determine the parameters of key components like compressor horsepower and pipeline throughput and, therefore, the costs of satisfying those parameters.

The market conditions and assumptions are crucial to both TEA and the NPV model in three ways. First, the assumption of the flow rate and capacity of the upstream hydrogen supply (for example, the capacity of an electrolyzer or the flow rate of an SMR plant) directly determines the injection capacity required for the storage project. Second, the downstream application's demand seasonality and volume determine the withdrawal capacity requirement. For example, if the storage project is serving a turbine for generating electricity sold to the grid, the withdrawal capacity of the storage is determined by the generation capacity of the turbine. At last, the working gas capacity of the storage asset is also determined on the basis of the estimated range of inventory given the interaction between injection and withdrawal over time. Assumptions about the working capacity of storage and the deliverability (injection and withdrawal) requirement then influence both the capital expenditure (CAPEX) and operating expenditure (OPEX) of the plant. For example, the storage facility's sizing for its pipeline size, casing, cavern size, and compressor capacity must be aligned with the capacity requirements. The capacity requirement then determines the operational limits and cycles of the plant, hence the revenue stream in the NPV model.

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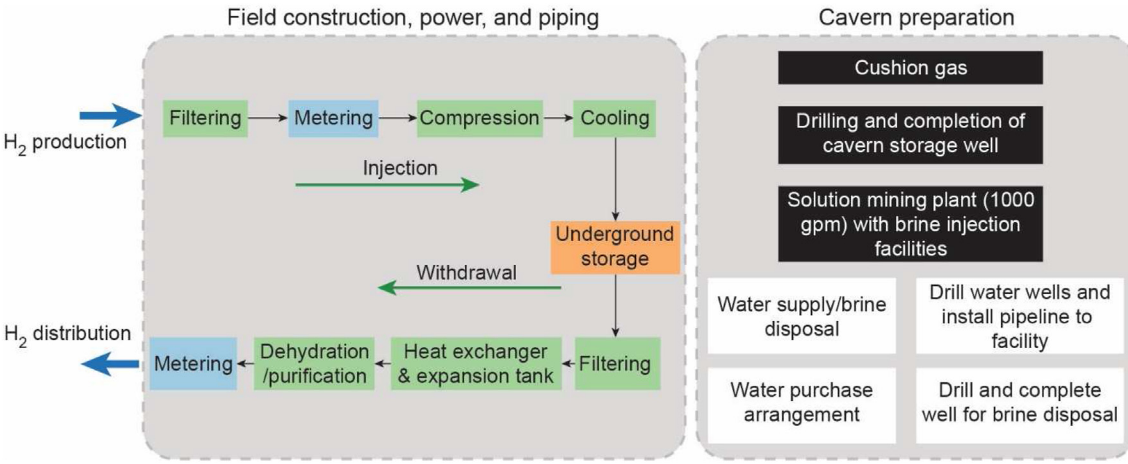

Fig. 4 – Hydrogen storage asset schematic.

TEA

The techno-economics model's basic components of capital costs include pipeline, well, site, solution mining (for salt cavern), and compressor. This study has included updated assumptions and data points from industry interviews[3] for each capital component to reflect more-realistic values. The storage asset may be collocated with other assets, like a hydrogen production source or a downstream application of hydrogen. Together with hydrogen storage, these assets form an energy system, which often determines the operation and utilization requirement of the storage asset. It is essential to note that the cost estimates and valuation analysis in this research only consider the storage asset itself, as described in Fig. 4.

Compressor

Compressor costs are based on the rate of work done by the compressor, which is the function of the inlet pressure, outlet pressure, and flow rate [7], as shown in Equation (1). For example, for a compressor to increase the pressure from suction pressure of 3204 kPa,[4] close to the outlet pressure of the electrolyzer, to the discharge pressure of 24,233 kPa, close to the well bottom-hole pressure, the power required is about 932.12 kW,[5] [53].

$$\textit{Compressor CAPEX} = f(\textit{Injection rate}, \textit{inlet pressure}, \textit{outlet pressure}) * \textit{compressor unit cost}(\textit{per unit of power})$$

Equation 1. Compressor CAPEX cost

Well and site development

Well drilling, completion, solution mining, and disposal are critical factors that determine the well cost and site development of salt cavern hydrogen storage.

For the well cost, one single casing is used for solution mining and later for gas operations. Often, the casing size to facilitate a practical construction timeline (18–24 months) is likely to be larger than required for injection and withdrawal operations. Sizing the casing too small leads to extra construction time due to the longer duration required for solution mining, while sizing it too large is costly and wasteful for the operation. The sizing of the casing and depth of the well determine the total capital cost of the well.

For solution mining, this study assumes a solution mining plant with 0.06309 cubic meters per second (1000 US gallons per minute)[6] throughput and brine injection facilities. Depending on the size of the cavern and site location, water supply and brine disposal can be handled either by drilling water wells and disposal wells close to the construction site with necessary piping to the facility or by contracting water purchase and brine disposal services. A project developer can also choose to outsource well drilling or solution mining to a third-party operator, which may cost more but limits additional risks associated with site development. Therefore, the range of costs for well construction and solution mining varies greatly depending on the specific development conditions and plans; well construction and solution mining make up the majority of the total CAPEX of the project.

One other factor in site development is cushion gas, which is purchased and stored in the cavern. Assuming integrity sufficient for the salt cavern to store hydrogen, the cushion gas can be recovered at the end of the project life. Therefore, this study considers the cost of cushion gas part of the working capital instead of the capital investment.

Price spread between withdrawal and injection prices

The economic valuation of a storage facility is a function of the price spread between injection and withdrawal, where the storage enables the ability to carry the product, hydrogen in this example, through time, hoping to take advantage of price fluctuation in the future market. One common scenario is to

[3] We thank United Brine, Global Gas Consulting LLC., and other professionals for their insights and expertise to the TEA, while remaining solely responsible for any error therein.

[4] kPa: kilopascal.

[5] kW: kilowatt.

[6] The SI unit for flow rate (gallons of water per minute) is cubic meters per second (m^3/s). 1000 US gallons per minute is approximately 63.09 L per second, or 0.06309 cubic meters per second.

consider an independent player that inject hydrogen at low prices, stores it and sells it when the price is higher, often along with periods of higher demand. The frequency and magnitude of higher demand differ for different downstream market segments, which are illustrated in the two case studies presented in this study. The price spreads indicate the different price levels across time, between withdrawal and injection. This difference is reflected as seasonal demand pattern, like winter prices versus summer prices for transportation fuel sector. In other scenarios, the difference occurs more frequently with high price volatility, like power prices.

Net present value and discount rate

Why use the net present value method?

Levelized cost of energy has been historically utilized in the preliminary cost analysis for energy-producing projects and technologies with a measurement metric of cost per unit of energy produced. The main purpose of LCOE is to demonstrate and compare the average overall cost required to produce one unit of energy, equivalent to determining the minimum revenue required per unit of energy produced to cover the unit cost [54]. The criteria for a company's manager to accept an independent (not mutually exclusive) project is that the project's LCOE can be covered by selling each unit of energy to the market. The criteria to accept a mutually exclusive project is that the project has the lowest LCOE that the revenue per unit of energy can cover.

Lord et al. [47] extended the levelized cost concept from energy production and applied it to geological storage. Xu and Lin[7] discovered key problems in such applications due to the uniqueness of geological energy storage and the differences between energy production and energy storage. Therefore, this paper does not continue to use the levelized cost approach to value hydrogen storage. Instead, the current research work establishes a comprehensive NPV model to evaluate geological hydrogen storage. The NPV model uses a scientific and fundamental cost–benefit analysis to conduct capital budgeting. It accounts for the time value of money, all the cash flows generated from the project, project risk, and cost of capital, including the cost of equity and cost of debt. When NPV is greater than zero, it means that the project will add value to the firm. For independent projects, all the projects with positive NPVs will be accepted. For mutually exclusive projects, the project(s) with the highest positive NPV will be accepted.

With the NPV framework, how NPV is changed with discount rate can be analyzed. The higher the discount rate, the less the value of NPV. The discount rate which leads to zero NPV, is called the international rate of return (IRR). IRR is the highest return that can be received from the project. With IRR criterion, managers should only accept a project when the project's IRR is greater than the cost of capital.

Net present value and free cash flow

The NPV equation (Equation (2)) follows:

$$NPV = \frac{FCF_0}{(1+i)^0} + \frac{FCF_1}{(1+i)^1} + \cdots + \frac{FCF_N}{(1+i)^N}$$

Equation 2. Net present value

In Equation (2), N is the project life, i is the discount rate, and FCF is free cash flow. FCF_0 is the initial investment, including initial CAPEX and the initial net working capital (NWC) tied to the project.

The established NPV model projects the benefits (revenues) that will be generated from the hydrogen storage and all the costs that will occur, including CAPEX, OPEX, tax liabilities, etc., and then calculates the free cash flow, the discounted present value of all the future FCFs, and NPV. Free cash flow is calculated as follows:

$$\begin{aligned} FCF &= EBIT \times (1 - Tax\ rate) + Depreciation \\ &\quad - (Change\ in\ gross\ fixed\ assets + Change\ in\ net\ working\ capital) \\ where: EBIT &= Revenue - Expenses - Depreciation \end{aligned}$$

Equation 3. Free cash flow

Assumptions

The following assumptions are made for the hydrogen geological storage NPV model.

- The project has a 30-year lifespan.
- One compressor will be used. The compressor has a 20-year lifespan; the initial compressor will need to be replaced in year 20. The after-tax salvage value of the second compressor is captured at year 30.
- The well has a 30-year lifespan.
- The storage site has a 40-year lifespan, and its after-tax salvage value is calculated at year 30.
- Construction is completed in year 0, and production starts from year 1 (if there is construction after year 0, it can be discounted back to year 0).
- At the end of the equipment life, the equipment salvage value is 10% of the equipment cost. If the project ends before the equipment's life, the salvage value is assumed to be the same as the equipment's remaining book value.
- Straight-line depreciation is applied for the fixed assets.
- Cushion gas cost is considered NWC, which will be recovered by the end of the project life. Other NWC is set as 10% of next year's revenue.
- The capital structure for the project: 40% equity finance and 60% debt finance.
- The capital asset pricing model (CAPM) calculates the required return for equity financing.
- Assume that investors will hold diversified portfolios and that only the non-diversifiable risk (systematic risk) will be factored into the cost of equity. In finance, beta is used to measure the systematic risk for an individual asset or a portfolio, defined as the systematic (non-diversifiable) portion of an individual asset's risk relative to the market as a whole.
- The systematic risk of hydrogen storage is estimated with comparable public companies. The betas of the comparable companies are unlevered and then relevered according to the project capital structure assumption.
- The weighted average cost of capital (WACC) is used as the discount rate for FCF.

[7] Xu and Lin, How LCOE Can Be Extended from Energy Production to Energy Storage? Working Paper 2023.

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Discount rate

Weighted average cost of capital (WACC)
The discount rate is determined according to WACC, accounting for capital structure, cost of debt, cost of equity, and marginal tax rate, as Equation (4) shows:

$$\mathrm{WACC} = \left(\frac{E}{V} \times R_e\right) + \left(\frac{D}{V} \times R_d \times (1 - T_c)\right)$$

Equation 4 Weighted average cost of capital

where R_e is the cost of equity, R_d is the cost of debt, T_c is the tax rate, E is the equity value, D is the value of debt, and V is equity value plus the value of debt.

Beta and cost of equity
The CAPM is used to determine the cost of equity, as Equation (5) shows:

$$R_e = R_f + \beta_L (R_m - R_f)$$ Equation 5. Capital asset pricing model

R_e is the cost of equity. R_f is the risk-free rate, R_m is market return, and β_L is the levered beta.

According to the assumptions above, this study uses comparable companies to determine the beta that captures hydrogen storage risk. The comparable companies have different capital structures from the hydrogen project, so the asset betas (levered betas) for the comparable companies are obtained first, then the equity beta β_U is calculated by unlevering the asset betas of the comparable companies according to Equation (6). Last, the average equity beta from the comparable companies is relevered again according to the hydrogen storage capital structure using Equation (7).

Table 1 – Assumptions for the WACC calculation.

The risk-free rate, R_f	4.23%
Market risk premium (R_m-R_f)	5.60%
Cost of equity, CAPM	16.85%
Cost of debt	5.44%
Debt–equity ratio	1.5
Cost of capital, WACC	9.16%

Table 2 – Geological site assumptions.

Variable	Salt cavern, site A	Salt cavern, site B
Formation pressure, kPa[a]	13,890.87	13,890.87
Formation temperature, °K[b]	310.93	310.93
Formation depth, m,[c]	1158.24	1158.24
Cavern volume, m^3	580,000	116,000

Note.
[a] 13,890.87 kPa is equal to 2014.7 psi (pound-force per square inch), and that is equal to 2000 psig (pound-force per square inch gauge).
[b] 310.93 K is equal to 100 °F. F = 1.8(K - 273) + 32, where K(kelvin) is the temperature in the SI unit, while F is the temperature in Fahrenheit.
[c] 1158.24 m is well depth, eqauls to 3800 ft [47].

Site B represents a second hypothetical site with a much smaller cavern volume, which can be a bedded salt formation. This section sets up the market scenario and operating design for each site, setting the stage for the valuation.

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c) * \left(\frac{D}{E}\right)\right]}$$ Equation 6. Unlevering the asset beta for the comparable companies

$$\beta_L = \beta_U * \left[1 + (1 - T_c) * \frac{D}{E}\right]$$ Equation 7. Relevering the beta according to the hydrogen storage capital structure

Cost of debt
Assume that the hydrogen storage project has a BBB credit rating. A value of the cost of debt in 2022 is applied to this study.

In summary, it is assumed that the risk-free rate is 4.23%, the highest risk-free rate in 2022 [55], the market risk premium is 5.6%, an average value of the market risk premium in 2022 [56], the cost of debt is 5.44%, the value of cost of debt with BBB credit rating on December 15, 2022 [57], and the capital structure is 1.5, which is calculated as a debt-equity ratio in this study. Based on the above assumptions, the calculated WACC is 9.16%, which is the discount rate for the hydrogen storage project. Table 1 lists the details of the assumptions and the calculated WACC.

Scenario assumptions

This study considered two hypothetical salt caverns, site A and site B. The cavern parameters are listed in Table 2.

Site A is a hypothetical salt cavern representing a potential site, similar to the existing assets in the Gulf of Mexico region.

Market scenario for site A—a single-turn salt storage[8]
The first scenario is a single-turn salt cavern storage project serving the seasonal peak demand of the transportation sector. The scenario assumes the existence of a local market of the transportation sector for hydrogen similar to one for city transportation described in Lord et al. [47]. Storage site A is a relatively larger cavern that stores peak incremental demand for city transportation demand for hydrogen. This scenario requires the storage of hydrogen for four months (120 days) of peak demand each year at a withdrawal rate determined based on daily demand as a function of population and fuel economy. For the source of hydrogen, this scenario assumes a steady rate of injection for the rest of the year (230 days), which can be a purchasing agreement tied to a local

[8] Turn refers to the number of times one can inject into and withdraw from a storage facility per year. A single-turn facility utilizes its working capacity once per year, while a multiturn facility can use its working capacity multiple times per year through more frequent injection and withdrawal.

hydrogen production source, like a steam reforming plant, at a fixed price of hydrogen.

The storage is a one-well design, and injection and withdrawal operations run on a time-sharing basis through one single well. The storage asset can only inject or withdraw, not do both at once. Given the market assumption, this storage site has.

- A total working capacity of 6,212,425 kg/yr of hydrogen, with 30% cushion gas.
- Injection capacity of 1125 kg/h (equivalent to 11.2 MMSCF/d) of hydrogen for 230 days; withdrawal capacity is 2157 kg/h of hydrogen for 120 days (equivalence to 21.5 MMSCF/d).
- The injection price of hydrogen here is about $1.50/kg, based on the levelized cost of hydrogen from a steam reforming process with carbon capture storage, with natural gas, electricity and water from the Permian Basin.

Market scenario for site B—multiturn salt storage

The second scenario considers leveraging hydrogen storage to cope with the load-leveling challenges of renewable power generation and stabilize the grid with reliable backup generation. The intermittency of wind generation and the daylight limitations of photovoltaic solar generation require energy storage to mitigate weather-driven fluctuations in wind and solar resources, time-shift excess power generation output to resource-constrained low-to no-sunlight hours and mitigate the impacts of extreme weather events. Geological gas storage has been considered before, especially for natural gas, for the security of supply it can provide for the power market [58], so the concept of serving the power sector with geological gas storage is not new. Hydrogen provides a solution to leverage renewable and CO_2-free but intermittent wind and solar electricity generation as renewable generation capacity grows.

The site B scenario considers hydrogen geological storage collocated with a local wind farm with an electrolyzer and a downstream power-generator turbine (which consumes 100% hydrogen). Specifically, the storage is a multiturn salt cavern that serves seasonal and daily peak demand for the electric sector. The architecture of the scenario consists of four components: wind turbines, an electrolyzer, hydrogen storage, and a gas turbine. The turbines comprise an 80 MW wind farm presumed to be in the Southwest Power Pool (SPP) electricity market to provide representative market data. One-year data for this market including day-ahead and real-time electricity prices and operation data including committed day-ahead wind generation and real-time wind generation of the wind farm are used in this analysis to support the scenario simulation. The granularity of the day-ahead prices and committed generation is hourly and the real-time prices and real-time generation granularity is every 5 min.

Fig. 5 shows the wind farm's real generation for 5-min intervals in megawatts from October 1, 2019, through September 31, 2020 and the real-time market price ($/MWh) used in the market simulation. In this scenario, the wind farm is upgraded with a 21 MW electrolyzer with 67% efficiency. The upgraded hydrogen electrolyzer gives the wind farm operator additional choices in response to prices. It commits to sell electricity when the day-ahead market (DAM) price indicates more revenue than expected from producing hydrogen. Feng et al. presented this optimization simulation with the same data in detail and concluded that the threshold price for producing hydrogen is $36/MWh on the day-ahead market [59]. When the day-ahead electricity price is less than $36/MWh, the wind farm is committed to producing hydrogen for that hour. However, the actual revenue is calculated based on real-time price, which can be higher or lower than the DAM price. The electrolyzer is connected to a geological storage asset, and the produced hydrogen is injected into the storage asset.

On the downstream (withdrawal) side, a turbine is connected to the storage unit, which withdraws hydrogen and produces electricity when there is a sufficiently high electric price in the market. A fuel cell has often been considered in preceding literature for connecting on the withdrawal side of the storage asset [59], but a fuel cell's capacity is relatively limited compared to a gas turbine. Currently, utility-scale turbines use 30% hydrogen as a fuel, while some major turbine manufacturers offer up to 100% hydrogen for electric generation [34,35]. In this simulation, the turbines are assumed to be able to take 100% hydrogen and to be able to ramp up on short notice if a real-time threshold price of $37/MWh is met. The choice of $37/MWh is set so that there is no overlap between injection and withdrawal of hydrogen. Based on the simulation of the 2019 historical real-time electricity price of SPP price, the average electricity price below $37/MWh, is $13/MWh.

Fig. 6 presents two charts that describe the injection and withdrawal pattern within 5-min intervals (top) and the working gas inventory level during the sample period. Although technically the storage site can sustain a turbine with a larger capacity, an optimally sized gas turbine of 65 MW is assumed for this scenario, with a 2% loss in storage. The assumption comes from the operation scenario where the working inventory of hydrogen returns to its starting point at the end of the year without requiring additional injection or leaving excess hydrogen (besides the cushion gas).

The salt cavern's parameters are estimated as follows given the market requirements throughout the sample year and assuming the same operation schedule for the entire lifetime of the salt cavern and no major shifts in market conditions.

- Working gas: 749,488 kg with 3.5 turns per year
- 294 equivalent days of injection; 16 equivalent days of withdrawal; Injection capacity: 415.6 kg/h (4.14 MMSCF/d); withdrawal capacity 5323.2 kg/h (53 MMSCF/d)
- A 30% cushion gas and 5% flexibility of drawing down cushion gas without impacting cavern integrity
- The injection price of hydrogen is $1.88/kg assuming on average $13/MWh of electricity with 80% utilization of electrolyzer [60].

The schematic of operating with one well for this scenario is constant injections and withdrawals that occur throughout each month of the year. At the same time, the duration of

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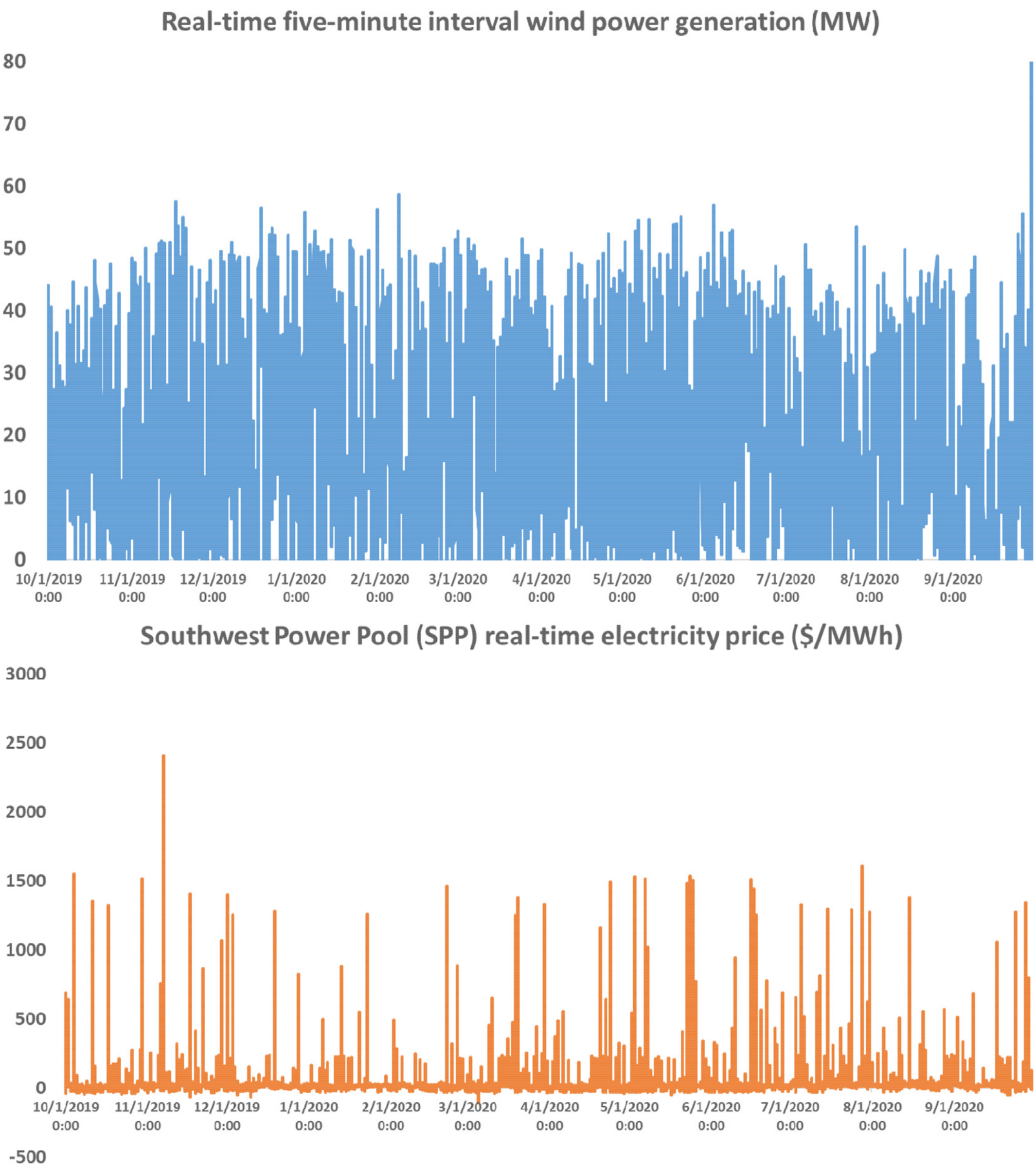

Fig. 5 – Southwest Power Pool wind farm generation and real-time market prices.

withdrawal increases in the peak electric season (late summer). It takes 294 days' equivalence of injection (the injection volume is not always at capacity) for 16 days' equivalence of withdrawal and consumption. The number of turns of the storage is calculated based on the total withdrawal gas throughout the year divided by the working gas capacity, implying that the storage asset completes 3.5 turns, cycling through 3.5 times of the working gas capacity in the calendar year. The electrolyzer capacity determines the injection capacity required for the cavern and the compressor horsepower. The turbine capacity determines the withdrawal capacity. In total, annual electricity being sold back to the grid is 25 GWh. The key value proposition for this scenario is to inject in the nonpeak season for hydrogen and withdraw during peak seasons for transportation to the downstream markets, which provides supply security and potential cost savings for downstream procurement.

Results and analysis

The established NPV framework can be used for three types of functions. First, calculate the NPV value of the asset and IRR given market conditions and prices of injection and withdrawal. This study uses an indicative market price of $4/kg to calculate the NPV and IRR. Second, in an emerging market like hydrogen, a clear market price is often absent due to a lack of transparency and liquidity, and this framework can be used to calculate the breakeven market condition (the minimum price spread) required for the storage project. At last, this framework can also provide sensitivity analysis on NPV and IRR, of prices or cost factors. With the established comprehensive NPV economic evaluation framework for hydrogen storage, this study has reached insightful and applicable results presented in this section.

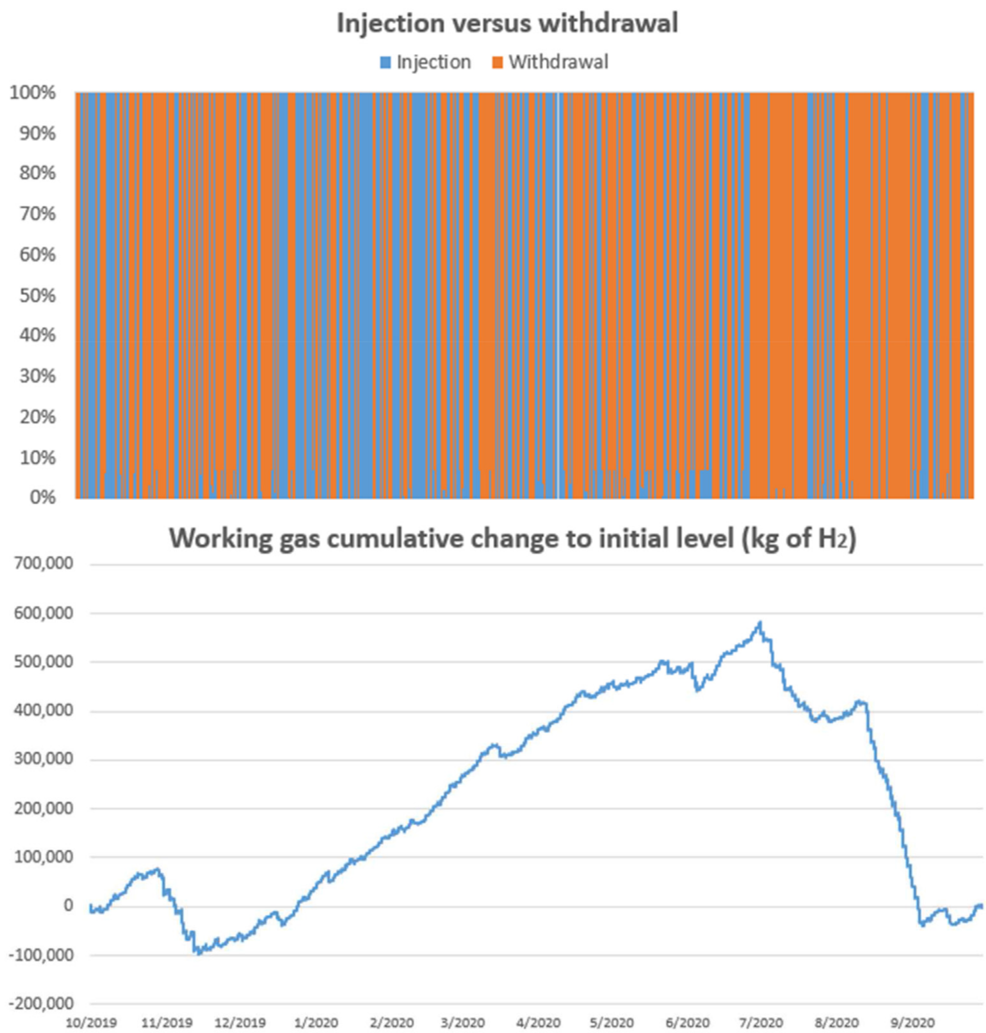

Fig. 6 – Site B injection and withdrawal pattern (top) and working gas inventory (bottom).

Results from the established net present value (NPV) framework

Table 3 provides both hydrogen storage assets' cost breakdown and NPV results,[9] including initial capital investment (CAPEX), initial net working capital required, and the total initial investment. The NPV of site A is $46, 560, 632, and the NPV for Site B is $12, 457, 546. The positive NPV results show that hydrogen storage will add value to the company, and thus it will increase shareholders' wealth. Positive NPV results meet the capital budgeting criteria for investors to take the hydrogen storage projects. The NPV framework can also calcualte the international rate of return (IRR), which is the highest return from the projects. Both sites have IRRs greater than the cost of capital, meeting the criteria for investors to take the projects.

[9] The $ 40 million of site development capital cost covers capital costs of cavern solution mining, cavern debrining, and brine utilization. The $18 milliosn of well capital cost covers capital costs of surface filtering, drying, heat exchange, and metering units. Compared to the cost analysis of Kobos et al., in 2011 and Lord et al., in 2014 [47,61], the cost estimations in this study is considered conservative.

Sensitivity analysis for NPV and IRR

In business practices, the valuation of an asset based on the techno-economics and net present value cash flow model not only provides one estimate, but more importantly a consistent approach to assess risks around the valuation results, or compare different scenarios and assets. Based on the NPV models of both storage assets, a sensitivity analysis of eight variables, with a range of ± 10%, reveals the range of impacts on the valuation results, specifically in terms of NPV and IRR (Fig. 7). The results are presented in tornado charts that rank price spread and costs from the greatest to the least. The top driver is the price spread between withdrawal and injection ($/kg H2), while site development including cavern preparation and solution mining, and well costs are also among the top assumptions in impacting the project valuation. This provides insights that site development is critical in screening for geological storage for hydrogen in salt caverns.

Table 3 – Project valuation summary.

Cost assumptions		Site A	Site B
Capital Cost[a]			
	Pipeline, $[b]	–	–
	Well, $[c]	18,000,000	4,200,000
	Compressor (year 0), $[d]	6,500,000	2,610,828
	Site development (does not include cushion gas), $[e]	39,840,000	8,000,000
	Total capital cost at year 0, $	64,340,000	14,810,828
Initial Net Working Capital			
	Cushion gas, $[f]	2,806,885	337,270
	Other NWC, $[g]	2,110,101	982,029
	Total initial NWC, $	4,916,986	1,319,299
Operating Cost			
	Compressor O&M on electricity, $/kg H2	0.120	0.116
	Compressor O&M on water and cooling, $/kg H2	0.012	0.012
	Well O&M, % of well CAPEX	4%	4%
	Dehydration, $/kg H2	0.004	0.004
	SGA: Sales and General Administration Expenses, % of revenue	1%	1%
Lifetime			
	Site, years	40	40
	Pipeline, years	30	30
	Well, years	30	30
	Compressor, years	20	20
	Project performance, years	30	30
Salvage Value			
	Salvage value at the end of life	10%	10%
Tax			
	Corporate tax rate	26%	26%
Discount Rate			
	WACC	9.16%	9.16%
Result			
Injection price[h]	$/kg	1.50	1.88
Withdrawal price[i]	$/kg	4.00	4.00
Total initial investment	F0, $	69,995,043	15,991,860
NPV	$	46,560,632	12,457,546
IRR	%	16.15%	17.37%
Profitability index	PI	1.67	1.78
Payback period, year	Payback period, years	6.00	12.50
Breakeven of price spread	$/kg	1.61	1.21

Note.
8$40 million of site development capital costs cover capital costs of cavern solution mining, cavern debrining, and brine utilization.
9$18 million of well capital cost covers capital costs of surface filtering, drying, heat exchange, and metering units.
[a] All costs and prices are in year 2020 real dollars.
[b] No last-mile pipelines are included in these scenarios.
[c] Single well; 13.375-inch casing for site B, and 20-inch casing for site A. Piping, gas handling and purification and dehydration units are included.
[d] Power requirement is 2623 kW with compressor unity cost of $2481/kW for site A; Power requirement is 558 kw with compressor unity cost of $3762/kW for site B.
[e] Includes solution mining plant (1000 gallons per minute), piping and drilling water wells for site A, and water purchase and disposal fee for site B.
[f] Hydrogen is used for cushion gas and is assumed to cost $1.50/kg, and cushion gas is treated as working capital and sold at the end of the project.
[g] 10% of the first year's revenue is as working capital.
[h] Injection price assumption for Site A is based on the LCOE of hydrogen from steam reforming with carbon capture and storage (CCS) from the Permian Basin, USA. The injection price assumption for Site B is based on the simulation of a power-to-gas system of producing hydrogen from a PEM electrolyzer and wind-powered electricity with on average $13/MWh of off-peak electricity price.
[i] Withdrawal price is an indicative market price of hydrogen from various sources: competitive cost of hydrogen lower bound of $4/kg from the Hydrogen Council's 2020 report [62].

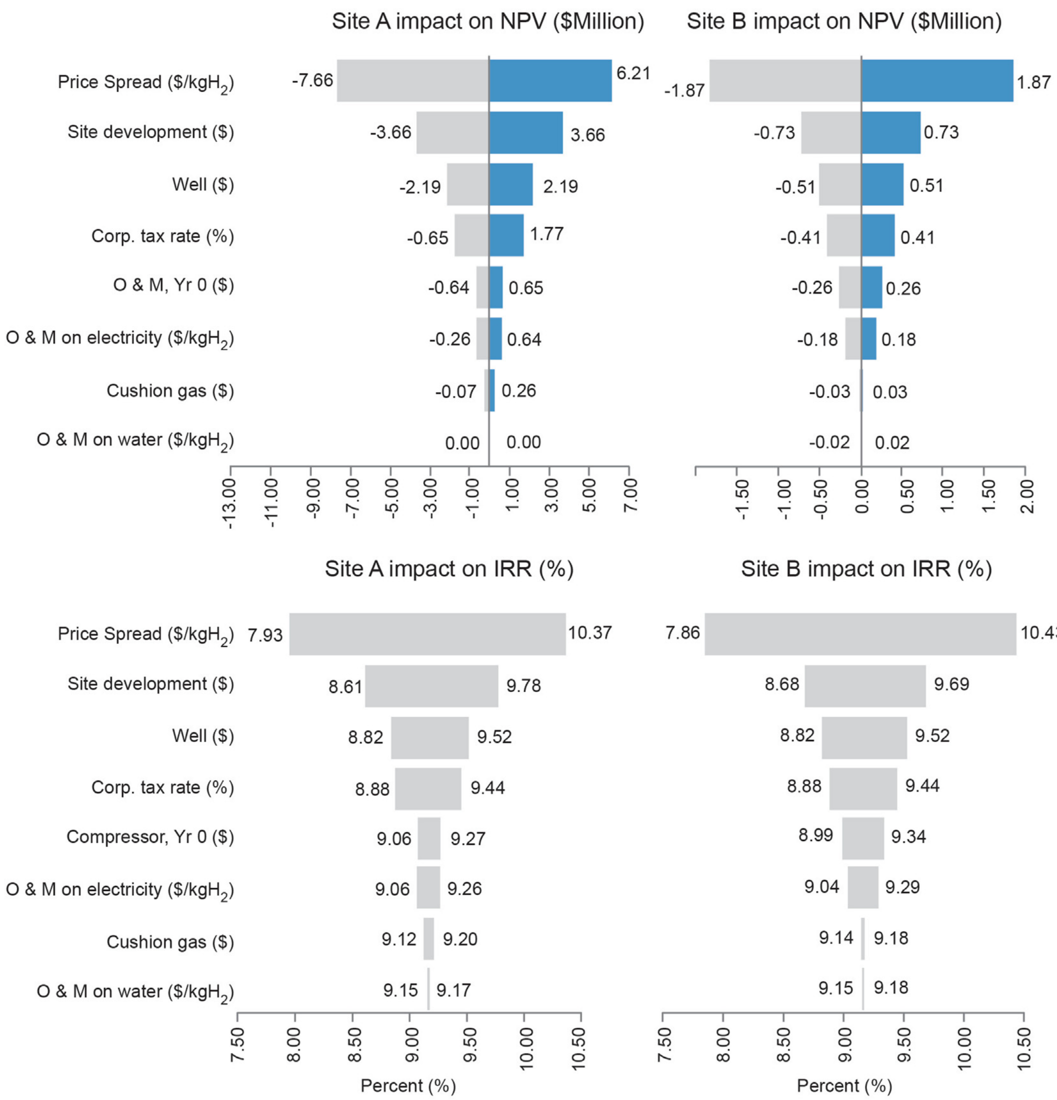

Fig. 7 – Sensitivity for NPV and IRR (Price spread = withdrawal price – injection price, and other cost factors).

Discussions on results

The two scenarios cover a range of differences in capacity requirements and operation schedules. The site A scenario considers a more conventional use of hydrogen storage for existing demand applications. This is similar to the value proposition and operational characteristics of the existing hydrogen storage in the United States, mainly built for seasonal swing demand for refineries and petrochemical sectors in the Gulf Coast of Texas and Louisiana.

The site B scenario leverages wind-based hydrogen production to stabilize the grid through turbine generation. It is a practical scenario for not only the SPP market but any other power market with a growing concern about the intermittency of renewables. Site B represents a smaller, multiturn salt cavern, like what could be constructed within a bedded salt formation, and is part of an integrated energy system sourcing hydrogen from wind power when electricity prices are low and regenerating electricity via gas turbine from hydrogen when electricity prices are high. This represents a unique value proposition for hydrogen storage as an effective solution for the intermittency of renewables. Site B has higher capital expenditures per storage capacity than site A. However, its multiturn operation schedule provides an efficient means of utilizing the storage and drives the required breakeven cost down even lower than that of site A. This result indicates that multiturn salt storage projects can be a commercially feasible investment option for the hydrogen value chain.

Extension of research

To extend the current research, one would consider a broader valuation perspective for the closed energy system (from the wind farm to electrolysis, storage, and turbine generation). This closed energy system can potentially mitigate peak-load shortages and prevent price spikes in the market. The authorial team's next research target is to evaluate such a system for the electricity market. Both scenarios consider salt caverns, but the same framework, TEA and NPV model methodology, can be adapted to depleted reservoir storage.

Conclusion

This study establishes a net present value (NPV) framework to evaluate the geological hydrogen storage assets. The NPV framework has been applied to two separate, realistic, and market-based valuations for the geological hydrogen storage sites. This research sets up a solid foundation for screening and investment activities related to geological storage assets and further research. The storage scenarios are important in regional infrastructure build-out for the hydrogen sector. Different potential storage sites can exist along the same value chain, each with unique geological, engineering, and market characteristics. The current framework is ideal for screening and comparing storage sites within the same market area and value chain or for screening new investment opportunities in an emerging location within the hydrogen economy.

The risk-adjusted cost of equity and the cost of capital for the established geological hydrogen storage NPV framework are determined using the capital asset pricing model (CAPM) and the weighted average cost of capital (WACC) method. The calculated risk-adjusted cost of equity is 16.85% and the cost of capital is 9.16% with debt-equity ratio of 1.5 and tax rate of 25%. From the NPV framework, both projects have positive NPVs, $46, 560, 632 and $12, 457, 546, respectively, and internal rate of return of 16% and 17%, which are higher than the cost of capital.

The NPV framework is also applied to the sensitivity analysis and shows that the price spread between the withdrawal price and the injection price, site development, and well cost are the top three factors that impact both NPV and IRR the most for both sites. The NPV framework can be used for project risk management by discovering the key cost drivers for the storage assets.

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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