CO_2 for Underground Energy Storage

A Potential Carbon Capture Utilization and Storage Alternative

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ABSTRACT

In light of the need to reduce CO_2 emissions from fossil fuel use, increased use of renewable energy has become one of the strongest available energy alternatives to date. However, one of the main issues slowing the penetration of renewable energy is its intermittent availability. A cost-effective and dependable bulk energy storage (BES) technology will be a critical component of the electric grid going forward. Furthermore, while solutions are being sought to quickly decarbonize the energy system, carbon capture and storage (CCS) technologies have been proposed as an effective tool to limit CO_2 emission from the use of fossil fuels. The deployment of CCS technologies has been slowed, however, by the lack of a regulatory or market driver and the high cost of the technology. For these reasons, increased effort has recently been focused on finding strategies for alternative use of CO_2 that could provide a potential offset for the cost of CCS, with the main goal of helping to accelerate its deployment.

Use of carbon dioxide for energy storage has been proposed as a concept that could help develop better BES systems while using CO_2, potentially providing a most needed offset for the cost of CCS. This proposition becomes more attractive if it has the additional potential of being combined with long-term geologic sequestration (GS) of CO_2.

This report reviews the ideas proposed so far on the use of CO_2 for energy storage in subsurface schemes, with the focus on two questions: 1) is the scale of CO_2 utilization meaningful to provide economic benefits to the energy storage scheme and/or CCS deployment and 2) do the proposed ideas have the potential to be combined with long-term GS of carbon dioxide?

From this review, it seems likely that using CO_2 for energy storage might be feasible only at small to moderate scales, with minor economic or storage potential for CCS operations. However, all the ideas to date are at an early stage of development, and most of the studies so far use simple models with assumptions that could greatly affect their feasibility and impact.

Keywords

Bulk energy storage (BES)
Capture carbon and storage (CCS)
CO_2 sequestration
Compressed energy storage (CAES)

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1 INTRODUCTION

In light of the need to reduce CO_2 emissions from fossil fuel use, the increased use of renewable energy has become one of the strongest available energy alternatives to date. However, as has been widely recognized, one of the main issues slowing down the penetration of renewable energy is its intermittent availability. This intermittency also carries strong challenges for its integration into the grid—in particular, to balance demand and supply of electricity. Therefore, a cost-effective and dependable bulk energy storage (BES) technology will be a critical component of the electric grid going forward. Such technology will be essential to manage supply and demand and to optimize the complex integration of several forms of energy, including nuclear, fossil-fuel-based, and renewable power.

While solutions are being sought to quickly decarbonize the energy system, carbon capture and storage (CCS) technologies have been proposed as an effective tool to limit CO_2 emission from the use of fossil fuels. Its deployment has been slowed down, however, by the lack of a regulatory or market driver and the high cost of the technology—especially CO_2 capture. For these reasons, increased effort has recently been focused on finding strategies for alternative use of CO_2 that could provide a potential offset for the cost of CCS, with the main goal of helping to accelerate its deployment.

Use of carbon dioxide for energy storage has been proposed as a concept that could help develop better BES systems while using CO_2, potentially providing a most needed offset for the cost of CO_2 capture. This proposition becomes more attractive if it has the additional potential of being combined with long-term geologic sequestration (GS) of the utilized CO_2.

This report reviews the few ideas that have been proposed to date [1, 7, 8, 9, 10] about the use of CO_2 for energy storage in subsurface schemes, with the focus on two questions: 1) is the scale of CO_2 utilization meaningful to provide economic benefits to the energy storage scheme and/or CCS deployment and 2) do the proposed ideas have the potential to be combined with long-term GS of carbon dioxide?

The proposed concepts to use CO_2 for subsurface energy storage are derived from compressed air energy storage (CAES) systems. This report begins by providing a review of CAES in the following section.

Underground Compressed Air Energy Storage

From the different BES technologies currently available, CAES has been identified as one of the most cost-effective alternatives when hundreds of megawatt-hours of energy storage is needed [2]. The basic concept for CAES is to use off-peak and low-cost electricity from the grid to compress air and store it for later use. When needed, at times of high peak of electricity, the compressed air is released from where it was stored to deliver power back to the grid. In the conventional CAES cycle (see Figure 1-1), the air is driven through a compressor, where the motor is powered with electricity from the grid, and stored in a container above-ground or a reservoir/cavern below-ground. When released, the compressed air is preheated, combusted, and expanded with a reheat turboexpander that drives the generator that produces the electricity. In this case, the combustor that heats the expanding air is operated with fossil fuels (natural gas or fuel oil). This is a diabatic process in which heat generated during compression is wasted—therefore, there is a need to reheat the air during expansion, which is done through the use of fossil fuels.

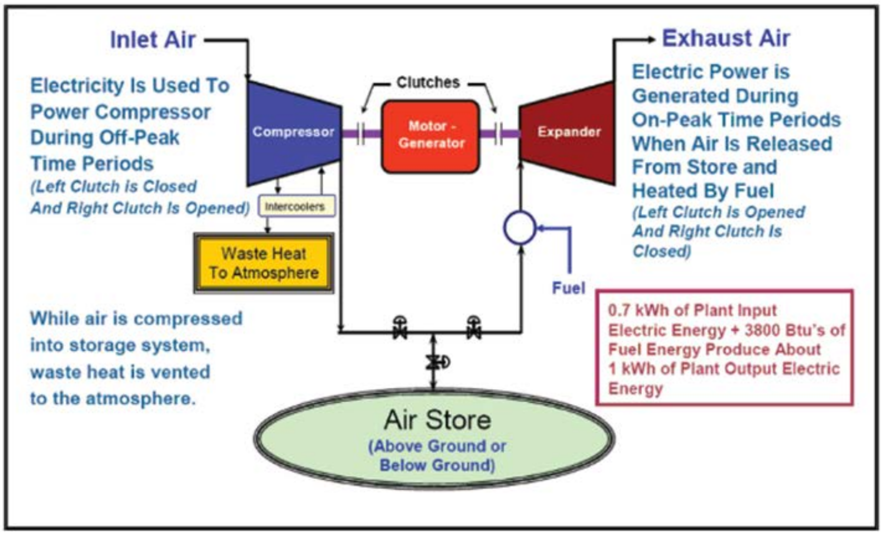

Figure 1-1
Schematic of a compressed air energy storage system [2]

A second type of CAES works in an adiabatic manner (A-CAES) by storing the thermal energy produced in the compression phase during off-peak electricity times and using it in the power generation phase, avoiding the need for fossil fuels and therefore avoiding CO_2 emissions.

In any of these types of CAES systems, it is possible to store the compressed air above-ground in pipes or vessels—a more flexible option but limited in size—or store it underground. For subsurface storage, the options include the following:

- **Caverns.** These include hard rock or salt caverns artificially mined. These constant-volume cavities are more straightforward to operate, but they are limited geographically.
- **Porous formations.** These are sedimentary rocks, similar to those used for CO_2 geological storage, and are more abundant geographically.

A special type of underground CAES, porous medium CAES (PM-CAES), uses permeable reservoirs (porous formations) as storage reservoirs [2, 3, 4]. These reservoirs include permeable sandstones, depleted gas or oilfields, or even naturally fractured limestones. These underground reservoirs, however, need to fulfill certain requirements such as the following:

- Maintain a pressure balance with the stored air; these formations should therefore be deep enough to sustain pressures on the order of ~4 to ~20 MPa (600 to 3000 psi)
- Provide sufficient thickness and permeability to ensure sufficient volume and adequate rate of airflow
- Have an impermeable seal above (and around) them to avoid leakage of the injected air

As mentioned, most of these requirements are shared with potential storage formations for carbon sequestration.

While there are two operating CAES plants with underground storage in caverns—in Germany and in the United States (Alabama)—PM-CAES has been only partially tested in two projects in the United States: in Iowa and California [3, 4, 5]. The fact that this idea has not been used at a full plant scale might seem surprising given that storing or producing fluids from porous reservoirs is a well-known practice in the oil and gas industry and in the seasonal gas storage business. The final report on the California test performed by Pacific Gas & Electric Company (PG&E) [5] states that the project demonstrated the technical feasibility of PM-CAES at an abandoned natural gas reservoir but lacked economic feasibility.

CAES Systems with CO_2

Even if CAES has been recognized as promising and one of the most cost-effective BES technologies, its development has been limited because of a few factors:

- Its low thermal efficiency, which ranges from ~40% in conventional CAES to ~70% in advanced adiabatic CAES (AA-CAES) [1, 6]
- CO_2 emissions from combustion of fossil fuels in the case of conventional CAES
- The specific requirements needed in the case of A-CAES/AA-CAES, which include high-temperature thermal storage and materials resistant to such high temperatures [1]

To overcome some of these limiting factors, CAES schemes with CO_2 instead of air have been proposed with the following potential advantages:

- Using CO_2 provides better energy density than using air because CO_2 density increases when it approaches its critical point [1, 3, 4].
- These systems offer an alternative use of CO_2 with the potential offset of cost/emissions and eventually co-sequestration of CO_2 in a combined energy storage–CCS operation.

2
LITERATURE REVIEW OF CO_2 FOR ENERGY STORAGE

As mentioned, this report will review proposed schemes in the literature of using CO_2 for underground energy storage with the focus on understanding whether the scale of CO_2 use is meaningful for offsetting emissions/cost and whether there is potential to combine energy storage with CCS operations [1, 7, 8, 9, 10]. Three main ideas have been explored in the literature that meet our criteria of interest:

- Using CO_2 as a cushion gas instead of air in PM-CAES [7]
- Using CO_2 in a transcritical and supercritical underground closed loop [1]
- Using CO_2 and enhanced geothermal energy combined with energy storage [8, 9, 10]

CO_2 as Cushion Gas in PM-CAES

In a traditional PM-CAES, air is used as the working fluid; as discussed in the previous section, it is compressed and injected underground into a porous formation to later be produced and expanded to generate electricity. However, most of the injected air is never recovered from the storage reservoir. The never-recovered portion of air is called *cushion gas*, and its function is to provide pressure support to the working gas. Oldenburg and Pan [7] proposed a scheme in which PM-CAES and geologic sequestration of CO_2 could be combined when CO_2 is used as the cushion gas. A similar idea has been explored in the context of natural gas storage [11].

PM-CAES with CO_2 has initially two appealing propositions:

1. CO_2 is an attractive cushion gas because its large increase in density near its critical point translates into high compressibility, which implies the potential to store more air (and therefore more energy) for a similar increase in reservoir pressure.
2. Relatively large quantities of CO_2 could be permanently stored at the back end of the reservoir.

To test their idea, the authors performed simplified fluid flow simulations as a proof-of-concept of an idealized system (see Figure 2-1) to understand both the extent to which the high compressibility of CO_2 could be a benefit in this type of system, and the mixing behavior of CO_2 and air. The latter could be a concern because if CO_2 is mixed with the working fluid (air), it could end up being produced and lost up the well.

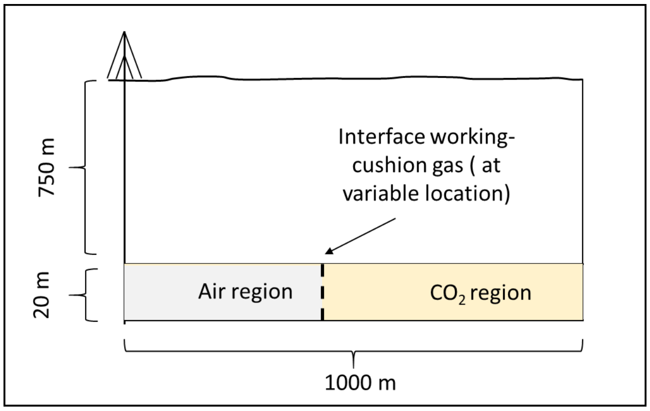

Figure 2-1
Sketch of PM-CAES system proposed by Oldenburg and Pan [7]. CO_2 is used as a cushion gas in a permeable reservoir at 750 m depth, where air is the working fluid, injected and produced in daily cycles. The location of the working cushion gas interface is varied in the simulations to investigate its optimal position.

This process has a few steps. The first is to inject CO_2 into the reservoir to position it as a cushion gas, followed by the injection of an air bubble that pushes the cushion gas to the back of the reservoir. These first steps are not modeled in the paper; rather, it is assumed that this has already happened similarly to CO_2 injection through a well into a permeable formation in sequestration projects.

Once the cushion gas is in place, operating the PM-CAES requires injection and production of air in daily cycles, which produces cycles of pressurization and depressurization near the wellbore, as well as gas mixing between the working and cushion gases (air and CO_2). There is a trade-off between the first and the latter effects that will be explained later in this report.

The simulated setup consisted of a 1-D radial model with pressure and temperatures equivalent to a reservoir at a depth of 750 m (2460 ft). The studied reservoir was defined as 25 m (82 ft) thick and extending up to 1 km (0.62 mi) from the well. The authors simulated several scenarios in which the amount of CO_2 varied as well as the position of the interface between air and CO_2. All simulations consisted of 30 days of daily CAES cycles in non-isothermal conditions.

After simulating 30 days of cyclic air injection in different scenarios, considering variable amounts of CO_2 and different positions of the interface between the working and the cushion fluids, following are some of the authors' observations:

1. The pressure difference at the well—testing different amounts of CO_2 and a scenario without CO_2 as cushion gas—was modest. The pressure oscillation during these cycles barely reached the area where the CO_2 was located (at the back of the reservoir).
2. When the air/CO_2 interface was located closer to the wellbore, the CO_2 entered the well in considerable quantities—implying a cushion gas loss as early as perhaps the first cycle (that is, when the interface was located ~20 m from the wellbore).

Note that the last observation implies that to maximize the compressibility advantage of using CO_2, the air/CO_2 interface should be positioned close to the wellbore. However, this configuration results in strong and detrimental air/CO_2 mixing because of the large fluid velocities that result in large dispersive fluxes, with the resultant CO_2 production (and loss) at the well. This is a result of the pressure gradients intrinsic in PM-CAES, which do not happen in contestant-volume caverns; as the authors point out, this is the main challenge in taking advantage of the "super-compressibility" of CO_2 for this proposed scheme.

The authors concluded that the best performance of the system occurs when the CO_2 cushion is at the far end of the reservoir, where CO_2 mixing with the air is slow. This configuration will sacrifice most of the compressibility advantages but will allow for significant quantities of CO_2 to be used—which could potentially influence the economics of the PM-CAES plant, depending on the price of CO_2. They emphasize that even if the compressibility advantage cannot be exploited as initially anticipated, in some situations the use of CO_2 as a cushion gas is still advantageous, especially if there is interest to combine it with CCS. Results from one scenario of this simplistic radial model indicate that if the air/CO_2 interface is located 500 m from the well (total reservoir length considered is 1 km) where little mixing is expected, the percentage of the total reservoir volume that could be occupied by CO_2 is 75%. In the most conservative case explored (with respect to mixing effects), where the interface is located 700 m away from the well, the percentage of the total reservoir volume that the CO_2 could occupy is ~50%.

With a simple formula, using the parameters of their simplified model (porosity, thickness, and CO_2 density for average reservoir conditions), the authors estimate that CO_2 stored could be on the order of 1.2 million tonnes of CO_2 as cushion gas. And although they point out that this amount is small compared to the annual emissions from a 1000-MW coal-fired power plant, the use of 1.2 million tonnes of CO_2 as a cushion gas could imply a positive impact (if there is a carbon tax or cap-and-trade policy) on the upfront cost of the PM-CAES plant. Furthermore, the authors used the non-radial case simulated by Kilinç and Gümra [12] as an example of what an operator could gain from storing the CO_2. They estimated the amount of CO_2 that could be used as a cushion gas (replacing the N_2 used [8]) on the order of ~12.5 million tonnes with a CO_2 price of $50/tonne; if they assume that 80% of the cost is allocated to CO_2 capture and transport, the geologic storage could still imply a benefit to the operator of $120 million.

In summary, it seems that PM-CAES could be an interesting idea for utilization and sequestration of CO_2 at modest and limited scales. However, more studies are needed to fully comprehend the behavior of the CO_2 as a cushion gas. More sophisticated models are necessary, considering the non-homogenous permeability structures of real reservoirs, potentially leading to higher transient pressure that could compromise the seal. Similarly, better understanding is needed of the geomechanical effects of the pressure of daily cycling and induced thermal stresses that could induce or trigger micro-seismicity. Furthermore, if the use of CO_2 cushion gas is attractive at least to offset some of the initial capital cost needed for a PM-CAES project, a whole system analysis would be necessary to understand the economics of such systems.

Two-Reservoir Compressed CO_2 Energy Storage System

The second idea reviewed here has been proposed by Liu et al. [1], in which the CO_2 is used as a working fluid in a closed loop. This idea tries to improve two of the main recognized drawbacks for CAES: its low thermal efficiency and its low energy storage density.

Liu et al. [1] proposed a compressed CO_2 energy storage (CCES) system using two underground reservoirs at different depths. As the authors point out, the concept of CAES comes from the Brayton cycle, which is more efficient when non-ideal gases (at the specific conditions of operation) are used. One such gas is CO_2, which in the proposed scheme could attain a higher performance than other CAES systems, such as AA-CAES [1, 13, 14].

In CCES, the appealing propositions (in the context of our review) are as follows:

- Achieve better performances by using CO_2 as the working fluid.
- Potentially reduce greenhouse gas emissions if this scheme could be combined with geologic carbon sequestration.

The CCES system shown in Figure 2-2 uses a shallower formation at low pressure to store CO_2 exhausted from the turbine and a deeper formation at a higher pressure where the CO_2 stored is from the compressor. As mentioned, this is done in a closed loop. The paper presents an analysis done in permeable formations, but the authors point out that it could also work in underground caverns. Furthermore, this system can be operated in two ways, based on the same principles differing only on the state of the CO_2:

- Transcritical compressed CO_2 energy storage (TC-CCES) system: CO_2 transitions from supercritical to gaseous conditions in the turbine
- Supercritical compressed CO_2 energy storage (SC-CCES) system: CO_2 is above its critical pressure during the complete cycle.

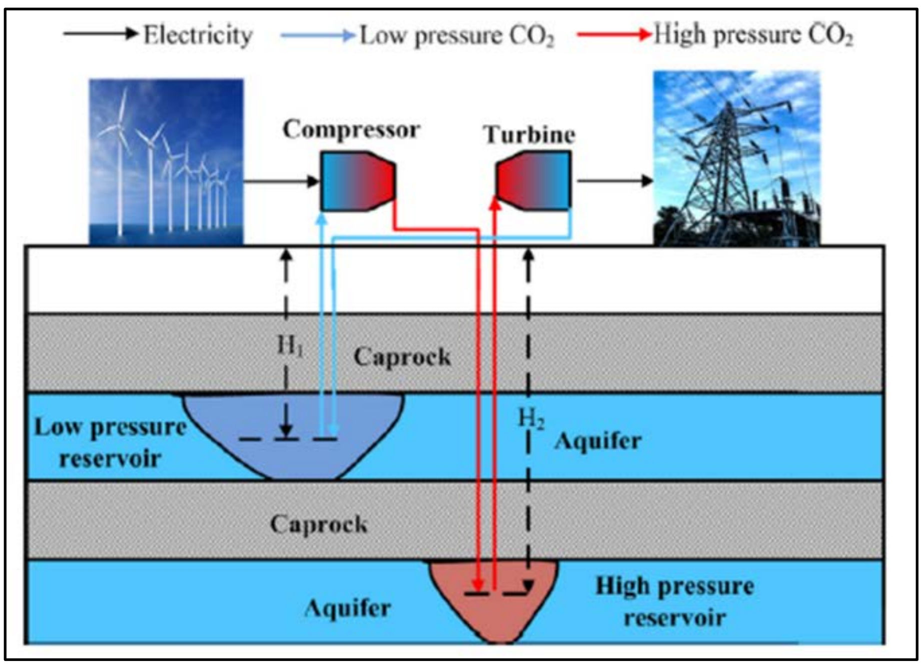

Figure 2-2
Compressed CO_2 energy storage system (CCES) using two underground saline formations [1]

The proposed scheme, illustrated in Figure 2-3, involves the following steps:

1. Using extra energy from the grid at off-peak times, low-pressure CO_2 (working fluid) is removed from the low-pressure reservoir (shallower unit) where it is stored and then pressurized and injected into the high-pressure reservoir (deepest unit).
2. In the case of a multi-stage compressor setup, the heat generated during the compression of the CO_2 is stored in a thermal energy storage (TES) system through a cooling fluid; the compressed CO_2, at the last-stage compressor, is then injected into the deepest reservoir.

3. When electricity is at high demand, the high-pressure CO_2 is delivered to the recuperator, passing through a throttle valve at a set pressure to absorb stored heat in the TES described in Step 2.

4. The CO_2 (heated and pressurized) is delivered to the turbine.

5. In the turbine the CO_2 expands, generating shaft work.

6. CO_2 exhausted from the turbine is stored in the shallower unit at low pressures.

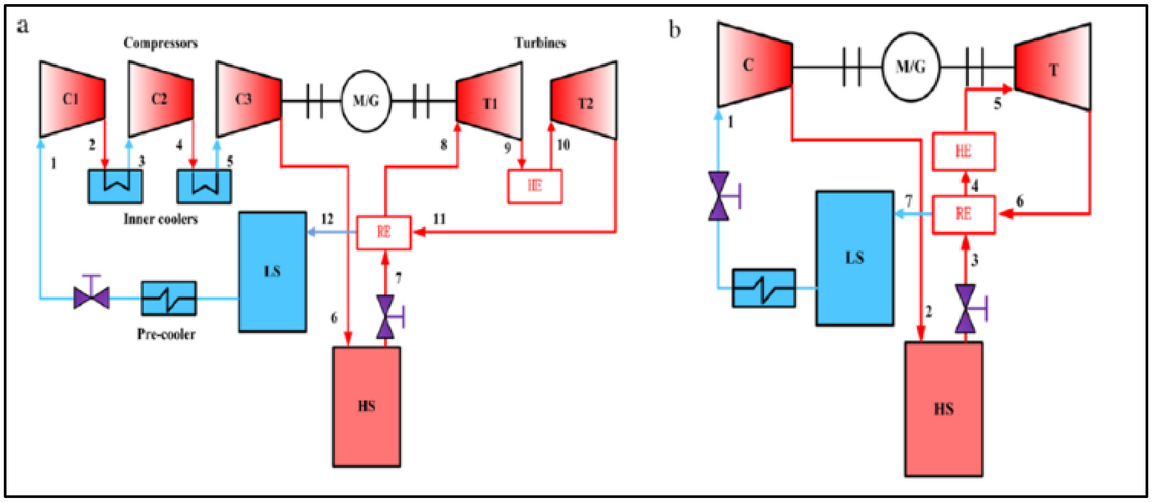

Figure 2-3
Compressed CO_2 energy storage system (CCES): a) schematic of TC-CCES; b) schematic of SC-CCES [1]

The paper focuses more on the thermodynamic analysis (exergy analysis) of the CCES systems than on the subsurface performance. The subsurface performance is incorporated only as a simple parametric study of a few subsurface parameters such as pressure, temperature, and volume of the reservoir. Volume is estimated using an analytical formula that assumes that the reservoirs are closed-storage formations [15]. The volume of the reservoir is:

$$s = \frac{M_{CO_2}}{(\beta_p + \beta_W)\rho_{CO_2}\Delta P}$$

where M_{CO2} = mass of CO_2; ρ_{CO2} = density of CO_2 at reservoir conditions; ΔP = magnitude of the pressure increase between the beginning and end of injection; β_p = pore compressibility; β_w = change in brine density.

The main objective of the analysis was to understand the thermal properties of the system, where the performance of the subsurface portion (that is, the behavior of the CO_2 in both reservoirs) is incorporated only to understand its effect on the overall system.

Summary of TC-CCES and SC-CCES Thermodynamic Analysis

Because of the variability among the different types of CAES systems, using a single-parameter performance index to compare them is not always possible [16]. In this case, the authors evaluate the performance of the TC-CCES and SC-CCES systems by analyzing their exergy efficiency, exergy destruction, round-trip efficiency, and energy storage density as the performance criteria of the general system and of the individual components [16, 17].

The indices used for comparison are energy storage density and round-trip efficiency, where:

$$\text{Energy storage density} = E_{GEN}/V_S$$

This corresponds to the amount of electrical energy produced per unit of storage capacity. This is a critical parameter to understand the underground geological requirements necessary for CAES. In this type that uses two reservoirs, the energy storage is:

$$\frac{E_{GEN}}{V_S} = \frac{W_t(\beta_P + \beta_W)\left(\rho_{1,CO_2}\Delta P_1 + \rho_{2,CO_2}\Delta P_1\right)}{2}$$

Round-trip efficiency: This parameter allows the comparison with other electrical storage devices and is defined as [16, 18]:

$$\eta_{RT,1} = \frac{E_T}{E_C + \eta_{NG} E_F}$$

In the above formula, E_T = electricity output; E_C = electricity input; $\eta_{NG} E_F$ = electricity that could have been generated from natural gas (E_F) in a stand-alone power plant fueled by natural gas and with efficiency input; η_{NG} instead of firing an energy storage unit input; η_{NG} = 47.6% [1].

In the exergy analysis, the authors analyzed the whole system as well as its components such as compressors, storage cavern/reservoir, heat exchanger, and turbine. The energy balance for the whole system is:

$$E_{F,tot} = \dot{E}_P + \sum_k \dot{E}_{D,k} + \dot{E}_L$$

where the variables are the total amount rate of fuel exergy ($E_{F,tot}$); product exergy ($\dot{E}_P$); exergy destruction ($\sum_k \dot{E}_{D,k}$) and exergy loss associated with the whole system ($\dot{E}_L$).

For details of the thermodynamic, energy, and exergy analysis as well as the sensitivity analysis, the reader is referred to the article by Liu et al. [1].

The authors concluded that the TC-CCES and SC-CCES systems have a larger energy storage density than regular CAES systems (see Table 2-1). Furthermore, they found acceptable round-trip efficiency and exergy efficiency for both cases.

Table 2-1
Performance evaluation summary of TC-CCES and SC-CCES and comparison with conventional CAES systems

	TC-CCES	SC-CCES	Conventional CAES
Energy storage density	497.68 kWh/m^3	255.20 kWh/m^3	2–20 kWh/m^3
Round-trip efficiency	63.35%	62.28%	
Exergy efficiency	53.02%	51.56%	81.7%

Comparing both systems, the authors noted that in the case of TC-CCES, all the indexes are higher; SC-CCES systems have a simpler configuration.

However, one of their findings could pose a significant challenge for this idea: the pressure of the shallower reservoir has a significant influence on the round-trip efficiency and exergy efficiency. This effect is especially larger for pressures below 8 MPa (1160 psi). Particularly with the TC-CCES, there is a dramatic decrease in both round-trip efficiency and exergy efficiency. The energy storage density was found to decrease when there is an increase in pressure of the shallower reservoir.

In the TC-CCES system, the authors noted that the low-pressure reservoir has to be at a much shallower depth than the supercritical CO_2 energy storage reservoir and have a much greater volume. These facts might create considerable environmental challenges, such as the potential impact to groundwater, which are more prominent in the transcritical case.

Other challenges the authors mentioned include the potential of induced micro-seismicity and brine production management or what they called *hydro-geomechanical limitations of the saline reservoirs*. Similarly, cyclic timing needs to be further investigated to understand the effect that transient pressure gradients would have near the injection and production wells [11].

The thermodynamic and energy and exergy analyses show promising results of using CO_2 as the working fluid for energy storage. However, these types of systems are unlikely to be meaningful at the scale of CO_2 utilization. It might be possible to further investigate these systems as part of a CCS project, but these cases might be opportunistic rather than a viable strategy.

CO_2 and Enhanced Geothermal Energy Combined with Energy Storage

Buscheck et al. [8, 9] have presented an intricate idea that combines CCS, energy storage, and enhanced geothermal energy. Given the vast storage capacity of the earth (fluid and thermal) and taking advantage of overpressures generated from CO_2 geological storage, the authors proposed a system to produce and store energy underground as well as provide excess energy to the grid [8, 9, 19, 20].

Part of their motivation stems from the need to help overcome some of the obstacles for carbon capture, utilization, and storage (CCUS) implementation as well as for energy storage implementation at a utility scale. These main obstacles are the overpressure generated for long-term CO_2 injection and the absence of a business case for CCS projects. In the case of energy storage, the main obstacles include storage capacity and cost. Therefore, since its inception, this idea is strongly linked to a CO_2 sequestration operation aimed at lowering carbon emissions while providing energy storage.

The CO_2 has a critical role in creating the overpressures that help recirculate the working fluids underground—fluids that store and recover energy. Furthermore, CO_2 is used as a working fluid in Brayton cycle turbines for electricity conversion and also as a shock absorber that allows cycles of recharge/discharge at lower pressure oscillation than other fluids. The authors claim that high amounts of stored CO_2 have a vast pressure-storage capacity that would help increase the scale of energy storage to a utility scale. The system is based on the previously developed CO_2 plume geothermal (CPG) concept and multi-fluid geothermal energy.

CPG [21, 22] uses CO_2 to extract heat from a geothermal reservoir as a renewable form of energy [23, 24]. There are several proposed variations to recover geothermal energy. Traditional systems harvest thermal energy with brine in very low-permeability reservoirs (usually fractured crystalline rocks). Other variations have been proposed using CO_2, which is more attractive as a working fluid because of its thermodynamic and fluid mechanical properties that allow it to transfer heat more efficiently than brine. An example of this case is the enhanced geothermal system with CO_2 (CO_2 EGC) [21]. In CPG, the difference is that the reservoir is a permeable sedimentary formation as opposed to low-permeability crystalline rocks. The advantages of using CO_2 as a working fluid include the following:

1. Lower kinematic viscosity than brine, which permits effective heat advection even if its heat capacity is relatively low
2. Higher thermal expansibility, which produces a stronger thermosiphon effect through the reservoir and the wells (injection and production) than with brine

The second concept, multi-fluid geothermal energy, is based on CPG but with the addition of producing brine (displaced by the pressure plume of the stored CO_2) to be used as an additional working fluid [8]. This scheme has also been proposed injecting N_2 to add operational flexibility.

The earth battery concept described in this report (see Figure 2-4) consists of a minimum of four circular and concentric rings of horizontal injection and production wells. As with the previous ideas, it has to be located in a permeable reservoir with an impermeable caprock above.

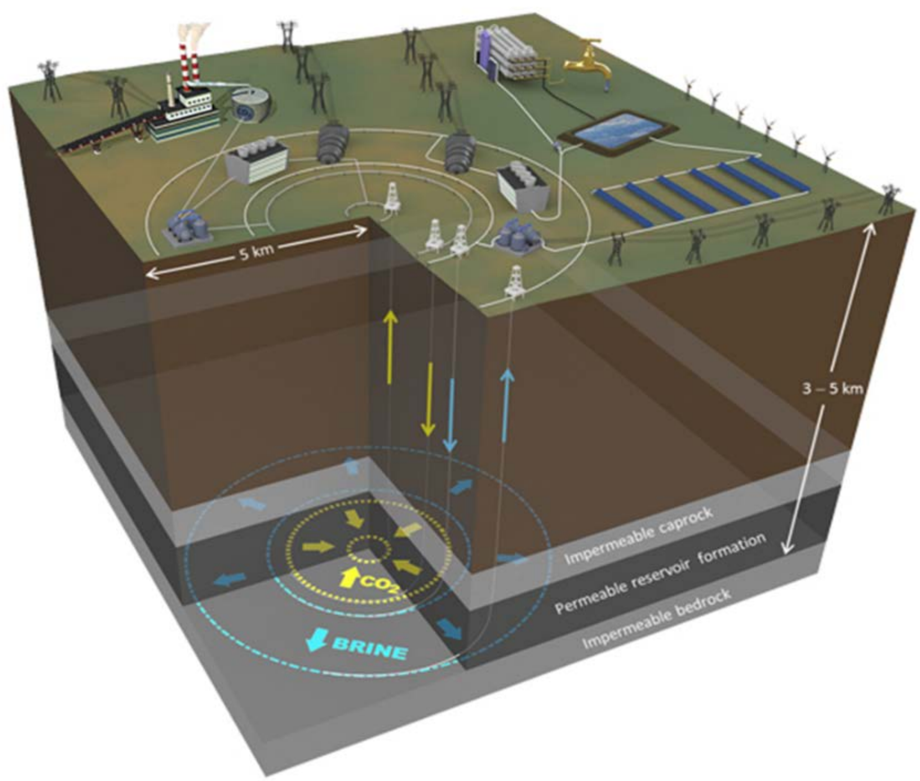

Figure 2-4
Earth battery concept [8, 9]

The system works as follows (see Figures 2-4 and 2-5):

1. Pressurized CO_2 (supercritical conditions) from a fossil fuel power plant is injected in the second ring of wells.
2. Brine is displaced inward by the injected CO_2 and produced at the innermost ring.
3. Produced brine is heated, using heat from an above-ground source (for example, solar thermal farm) and pressurized for re-injection.
4. Heated and pressurized brine is then injected in the third well ring, using excess power from the grid.
5. Gradually, the inner ring produces CO_2, which is sent to the surface to be used as a working fluid, through a Brayton cycle turbine.
6. After passing through the turbine, CO_2 is pressurized and re-injected in the second ring (similar to Step 1).
7. Hot brine is also produced at the outer well ring and is used to heat produced CO_2 before being stored in a staging pond. When waste/excess heat is available, brine from the pond is heated and pressurized for injection in the third well ring (as the brine in Step 4), using excess power from the grid.
8. To manage reservoir pressure, some of the produced brine is diverted for consumptive use, such as in a reverse osmosis plant or to cool down the power plant and reduce the plant's water intensity [8].

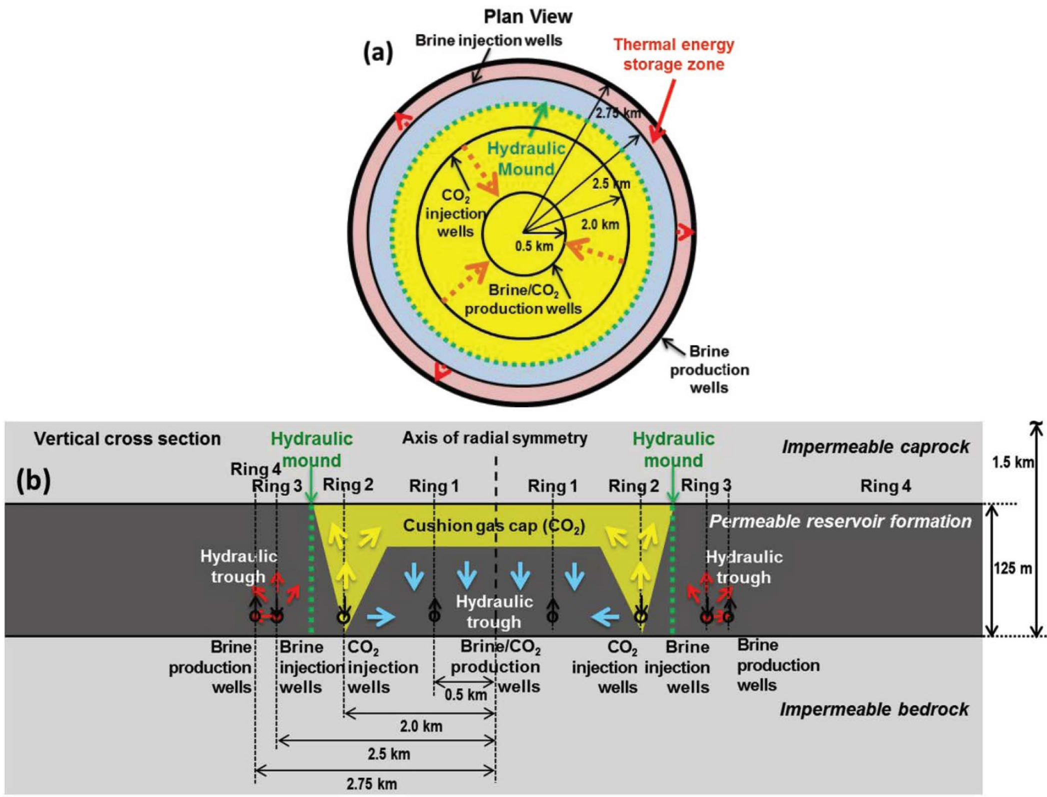

Figure 2-5
Cross-section of the underground system (a) and plan view of the well configuration dimension (b) in the reported study

According to the authors, one of the proposed advantages of this approach is that because fluid production is driven by overpressure, there is no need for submergible pumps to lift them; therefore, it is faster to increase production if needed (for example, deficits in the grid) or decrease in periods of low demand. In the latter case, pressure and thermal energy would be stored underground for a time when demand is high.

The analysis performed so far on this idea include fluid flow reservoir simulations performed with the NUFT code [25, 26] loosely coupled with a simplified techno-economic analysis at industrial scale. The authors have investigated daily and seasonal schemes. The simulated subsurface model is a generic homogeneous reservoir complex that includes a 125-m thick reservoir, with a permeability of 100 millidarcy (mD), a caprock and bedrock, and the two low-permeability (0.001-mD) seals at the top and bottom of the reservoir, respectively. The reservoir was assumed to be 1.5 km deep and a temperature of 70.0°C (with a geothermal gradient of 37.5°C/km).

From the reservoir simulation, the authors obtain the production flow rates and temperatures at the bottom of the wells for both power generation streams: supercritical CO_2 and brine. Those parameters are then used as input to calculate gross power into the GETEM code [27]. GETEM is an Excel-based code with financial and technical inputs that optimizes for reservoir and power plant performance to provide levelized cost of electricity (LCOE) from a geothermal power plant. In the brine generation stream, gross power is determined from the organic Rankine cycle

(ORC) binary power generation if reservoirs are 3 or 4 km deep. If the depth is 5 km, a flash-steam power plant is used for gross power. In the case of the CO_2 generation stream, supercritical CO_2 is circulated through a turbine, and electricity is generated in a Brayton cycle (direct) power system.

The authors considered eight scenarios varying storage temperature, net CO_2 storage rate, number and cost of wells, and power plant cost. They then calculated the levelized cost of storage (LCOS, in $/MWh) for a greenfield, which considers the well development costs, and a brownfield, where wells are assumed to be in place—and therefore there is no cost associated with them (see Figure 2-6). The values of LCOS are for a capacity factor of 95%.

Storage temperature (°C)	Net CO_2 storage rate (MT/yr)	Number of		Well-development cost (M$/well)	Power-plant cost ($ per net kW)	Levelized Cost of Storage LCOS ($/MWh)	
		Injectors	Producers			Greenfield	Brownfield
150	3.8	46	61	3.397	2148	74.3	46.9
150	7.6	82	109	3.385	2603	75.1	44.7
200	3.8	53	71	3.379	1647	45.4	32.4
200	7.6	98	130	3.359	1583	44.2	30.9
250	3.8	59	78	3.366	1257	31.0	24.2
250	7.6	110	146	3.367	1202	29.8	22.9
275	3.8	62	83	3.369	1141	28.2	21.9
275	7.6	115	153	3.355	1089	27.2	20.7

Figure 2-6
Summary of cases considered in the multi-fluid geothermal energy study

The two CO_2 storage rates analyzed (3.8 and 7.6 MT/yr) are equivalent to CO_2 captured from a coal power plant of 550 MW and 1100 MW, respectively. The temperatures considered at the storage reservoir ranged from 150°C to 275°C. The authors estimated that at temperatures ≥250°C, the potential energy storage capacity reaches 150% to 200% of the energy generated by this type of coal power plant. Furthermore, they calculated an LCOS of $60/MWh or less, with a 50% capacity factor.

This is a proof-of-concept type of analysis, with very simplified models, as the authors also point out. It needs further work to develop more sophisticated, more representative subsurface models as well as techno-economic models of the well configuration and the power system. Furthermore, research into the subsurface energy storage system and surface sources of thermal energy and electric grid integration is necessary [8, 9].

In our opinion, one major simplification that could dramatically affect the subsurface performance of this system is that underground reservoirs are not homogeneous as simulated—therefore, the fluid flow paths will not be homogeneously radial as depicted here. Changes on this configuration would have major implications for the working fluid and thermal energy recovery [8]. More research on the surface performance of the system might shed light into the feasibility of the proposed idea. Another component that needs addressing is the geomechanical effects of the overpressure generated by the CO_2 (and brine) injection and the cyclic injection and production of fluids. Even if overpressure in the reservoir is not high enough to break the overlying formation (seal), the amounts of overpressure simulated in the work—as well as thermal stresses—could be sufficient to induce or trigger micro-seismicity. Finally, the well configuration—although ideal for underground performance—is complicated. Even if technically feasible, it is not clear from the data presented whether the well costs used in this study are representative of such technical complexity. If feasible, this system could be an attractive approach for CCUS combined with energy storage.

CO_2-Plume Geothermal with Energy Storage

In a small variation from the previous paper, Fleming et al. follow some of the same principles proposed in Buscheck et al. [8] by combining CPG with CCS and energy storage, as well as a multi-reservoir configuration that allows for a time divergence between generation and consumption of energy as also proposed by Liu et al. [1]. However, in this case, the well configuration is simpler (either using only vertical wells or adding only two horizontal circular wells in the deeper unit), as opposed to the circular concentric horizontal wells proposed in Reference [8]. In this case, the heating is mainly performed with geothermal energy at the reservoir, whereas in Reference [1] the heating is performed at the surface.

In this CO_2-plume geothermal energy storage (CPGES) system, sequestered CO_2 is used as the energy storage fluid (storing pressure). If it remains at reservoir conditions (high temperature) long enough, it could absorb the geothermal energy input and generate more energy than the amount of energy originally stored. The proposed scheme works in two modes: power generation and energy storage (see Figure 2-7).

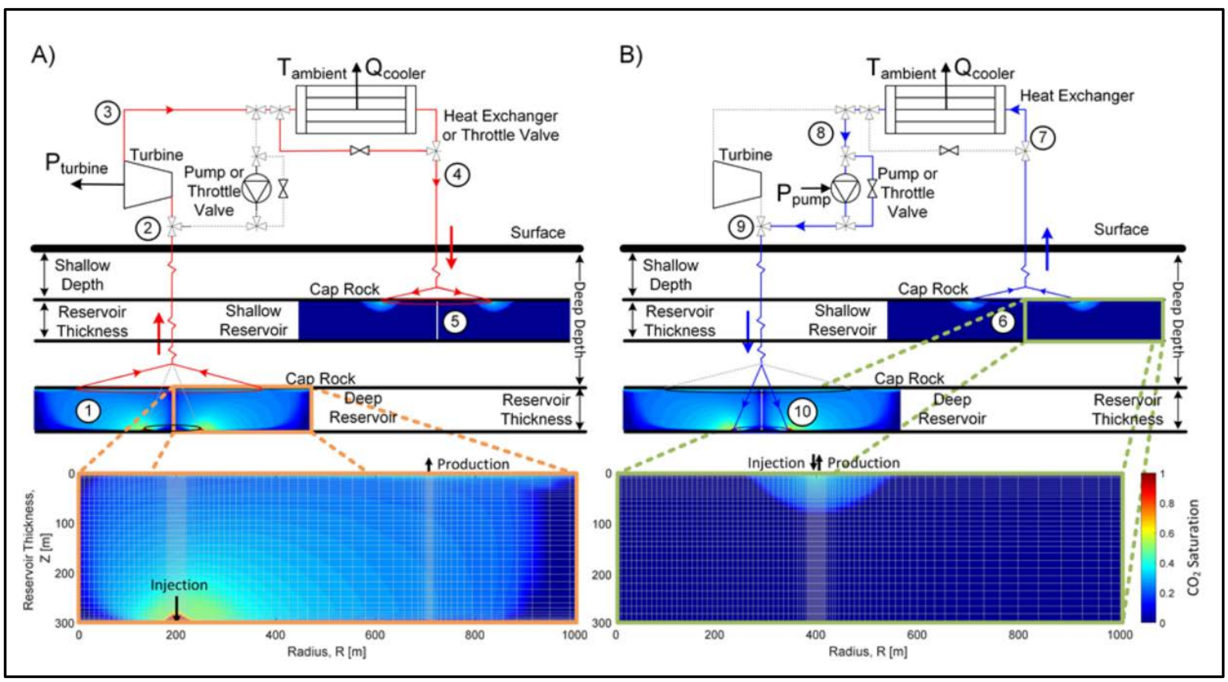

Figure 2-7
CO_2-plume geothermal energy storage system

In power generation mode:

1. CO_2 previously injected into the deeper reservoir is produced through a vertical well to the surface. This CO_2 is hot because of geothermal heat. The deep reservoir has two wells—one injection and one producer—so the CO_2 can extract heat from the formation as it flows through the reservoir.

2. At the surface, the CO_2 is expanded in a turbine to produce power and partially cooled to prepare it for re-injection.

3. Partially cooled CO_2 is re-injected into the shallower reservoir (at 1.5 km depth). because of its increase in density (through the cooling), the gravitational compression in the vertical well is sufficient to drive the re-injection. The shallow reservoir operates with only one well.

4. CO_2 is stored in the shallower reservoir until the generation cycle is finished.

In energy storage mode:

1. At times of surplus electricity from the grid, CO_2 from the shallow reservoir is produced back to the surface.

2. At the surface, CO_2 is cooled and compressed using electricity from the grid.

3. CO_2 is re-injected into the deeper reservoir.

The analysis performed in this paper uses two models: a fluid flow simulation performed with TOUGH2 [28] to model two reservoirs below the critical depth for CO_2 at 1.5 and 2.5 km depth and a surface power plant model performed with the engineering equation solver (EES) [29].

Two power cycles are analyzed:

- A diurnal cycle that produces power for 16 hours and stores energy for 8 hours—the periods of high and low cost of electricity [30]
- A seasonal cycle that operates in power generation mode for the first three months and in energy storage mode for the other three months

System performance is evaluated by the net energy produced, which is the difference between the energy generated in the generation mode and the energy used during the storage mode:

$$E_{Net} = E_{net,generation} - E_{storage}$$

The cases and results presented by these authors are summarized in Figure 2-8. They indicate that higher mass flow rates translate into a smaller energy storage ratio, whereas the average generation and storage power increases. With longer cycle durations (from daily to biannually) the energy storage ratio also decreases, but overall the energy storage ratio of the studied cases is larger than 1—a result that leads the authors to claim that the CPGES system in both cycles provides more electricity to the grid than the amount it stores from the grid.

Generation Time	Storage Time	Generation Mass Flow Rate (kg/s)	Storage Mass Flow Rate (kg/s)	Generation Average Net Power (MW)	Storage Average Net Power (MW)	Energy Storage Ratio (MW-h/MW-h)
16 hours	8 hours	200	380	1.63	1.11	2.93
16 hours	8 hours	300	570	2.29	2.33	1.95
3 months	3 months	200	190	1.50	0.99	1.55
3 months	3 months	300	285	1.97	1.87	1.05

Figure 2-8
Summary of the key performance characteristics of the CPGES system [30]

This system seems simpler than that of Buscheck et al. [8, 9] because of the possibility of using vertical wells and perhaps a fewer number of wells. However, it is still at a simple stage of modeling, and more work is necessary to understand the feasibility of such systems.

3
SUMMARY

From our review, it seems likely that using CO_2 for energy storage might be feasible only at small to moderate scales, with minor economic or storage potential for CCS operations. However, all the ideas to date are at an early stage of development, and most of the studies so far use simple models with assumptions that could greatly affect their feasibility and impact.

Table 3-1 presents a summary of the ideas reviewed in this report. Most of them are at an early stage of simplified/proof-of-concept type of modeling. Although none of them has been tested in the field, CO_2 as a cushion gas in PM-CAES [7] builds on a partially tested PM-CAES scheme that was determined technically feasible in one test [5].

Table 3-1
Summary of literature review on CO_2 for energy storage ideas

Technology	Maturation	CO_2 Utilization Potential	Long-Term Storage Potential	Tested	Type of Modeling	Techno-Economic Analysis	Citation
CO_2 as Cushion Gas in PM-CAES	Early stages; building on other partially tested systems (PM-CAES)	Moderate	Moderate	Model only	Multi-phase heat and mass flow transport in porous media (TOUGH2)	No	Oldenburg and Pan 2014 [7]
Super- and Transcritical CO_2	Very early	Minimum	Only if combined with a storage operation, but might be opportunistic	Model only	Thermodynamic analysis (energy and exergy) with parametric subsurface considerations	No	Liu et al. 2016 [1]
CPGES (Earth Battery)	Very early	Moderate to large	Moderate to large	Model only	Multi-phase heat and mass flow and reactive transport in porous media (NUFT) and simplified techno-economic (GETEM)	Yes, simplified	Buscheck et al. 2017 [8]
CPGES	Very early	Moderate	Moderate	Model only	Multi-phase heat and mass flow and reactive transport in porous media (TOUGH2) and engineering equation solver for surface power plant	No	Fleming et al. 2018 [10]

In the case of PM-CAES with CO_2 as a cushion gas, the approach proposed by Oldenburg and Pan [7] could be an interesting idea for utilization and sequestration of CO_2 at moderate scales; however, more studies are needed to fully comprehend the behavior of the CO_2 as a cushion gas. Among the issues that need to be better understood are consideration of the non-homogenous permeability structures of real reservoirs, the potential development of cyclic transient pressure that could compromise the seal [7] and perhaps trigger micro-seismicity, and the geomechanical effects on the reservoir and near the wellbore of daily cycles of production and injection. A whole techno-economic analysis is needed to understand whether using CO_2 as a cushion gas could help the economics of a PM-CAES plant, given that there is a price for carbon.

In the case of a transcritical and supercritical underground closed loop for energy storage [1], although this approach seems attractive from an energy storage perspective, it does not seem as attractive from a CO_2 utilization or potential long-term storage perspective.

In the final idea reviewed here—using CO_2 and enhanced geothermal energy combined with energy storage [8, 9, 10]—although the idea seems very attractive from a potential impact on the used and long-term stored CO_2, the configuration of the system (both in the subsurface and at the surface) seems extremely complex. More research is needed to indicate potential feasibility.

4
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